BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
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COMMISSIONERS

JEFF HATCH-MILLER Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.

DOCKET NO. E-01345A-03-0437

DECISION NO. 67744

OPINION AND ORDER

DATES OF PROCEDURAL CONFERENCES: August 13, 2003, January 6, February 18, April 7, 15, 28 May 26, June 14, August 18, and October 27, 2004

DATES OF HEARING: November 8, 9, 10, 29, 30, December 1, 2, and 3, 2004

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Lyn Farmer

IN ATTENDANCE:

Marc Spitzer, Chairman
William A. Mundell, Commissioner
Jeff Hatch-Miller, Commissioner
Mike Gleason, Commissioner
Kristin K. Mayes, Commissioner

APPEARANCES:

Mr. Thomas L. Mumaw and Ms. Karilee S. Ramaley, PINNACLE WEST CAPITAL CORPORATION; Mr. Jeffrey B. Guldner and Ms. Kimberly Grouse, SNELL & WILMER, L.L.P., on behalf of Arizona Public Service Company;

Mr. C. Webb Crockett, FENNEMORE CRAIG, P.C., on behalf of AECC and Phelps Dodge;

Mr. Patrick J. Black, FENNEMORE CRAIG, P.C., on behalf of Panda Gila River;

Mr. S. David Childers, LOW & CHILDERS, P.C., Mr. James M. Van Nostrand, and Ms. Katherine McDowell STOEL RIVES, L.L.P., on behalf of Arizona Competitive Power Alliance;

Mr. Lawrence V. Robertson, Jr., MUNGER

CHADWICK, on behalf of Southwestern Power Group II, Mesquite Power, and Bowie Power Station, LLC, and Mr. Theodore Roberts, SEMPRA ENERGY RESOURCES, on behalf of Mesquite Power;

Mr. Scott S. Wakefield, Chief Counsel, and Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

Mr. Walter W. Meek, President, on behalf of the Arizona Utility Investors Association;

Mr. Raymond S. Heyman, Ms. Laura E. Schoeler, and Ms. Laura Sixkiller, ROSHKA, HEYMAN & DeWULF, on behalf of UniSource Energy Services;

Major Allen G. Erickson on behalf of the Federal Executive Agencies;

Mr. Jay I. Moyes, MOYES STOREY, on behalf of PPL Sundance and PPL Southwest Generation Holdings;

Mr. Nicolas J. Enoch, LUBIN & ENOCH, on behalf of the International Brotherhood of Electrical Workers;

Mr. William P. Sullivan and Mr. Michael A. Curtis, MARTINEZ & CURTIS, P.C., on behalf of the Town of Wickenburg, Arizona;

Mr. Bill Murphy, MURPHY CONSULTING and Mr. Douglas V. Fant, LAW OFFICES OF DOUGLAS V. FANT, on behalf of the Arizona Cogeneration Association;

Mr. Marvin S. Cohen, SACKS TIERNEY, P.A., on behalf of Constellation NewEnergy and Strategic Energy;

Mr. Andrew W. Bettwy and Ms. Karen S. Haller, on behalf of Southwest Gas Corporation;

Mr. Timothy M. Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, and Ms. Anne C. Ronan, on behalf of Western Resources Advocates and Southwest Energy Efficiency Project;

Mr. Jesse A. Dillon, on behalf of PPL Services Corporation;

Mr. Brian Babiars and Ms. Cynthia Zwick, WESTERN ARIZONA COUNCIL OF GOVERNMENTS, on behalf of Arizona Community Action Association;

Mr. Paul R. Michaud, MICHAUD LAW FIRM, on behalf of Dome Valley Energy Partners, LLC;

Mr. Michael L. Kurtz, BOEHM, KURTZ & LOWRY, on behalf of Kroger Company;

Mr. Christopher Kempley, Chief Counsel, Mr. Jason D. Gellman and Ms. Janet F. Wagner, Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

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BY THE COMMISSION:

I. DISCUSSION

On June 27, 2003, Arizona Public Service Company ("APS" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a rate increase and for approval of a purchased power contract. The application states that the $175.1 million rate increase is needed to maintain the Company's credit ratings and attract new capital on reasonable terms, recover its cost of service, and permit APS to earn a fair rate of return on the fair value of its assets devoted to public service. The application requested that the Commission recognize the higher fuel and purchased power expenses being incurred by the Company; allow APS to include in rates at cost of service certain generation assets of Pinnacle West Energy Corporation ("PWEC"); permit APS to recover the $234 million write-off taken under the 1999 Settlement Agreement; and provide for the recovery of all prudently incurred costs to comply with the Commission's Retail Electric Competition Rules, A.A.C. R14-2-1601, *et seq.* ("Electric Competition Rules"), including the one-third of costs associated with the planned divestiture of generation from APS to PWEC that was not previously deferred. APS also requested approval of depreciation and amortization rates and a review of its long-term purchased power contract with PWEC if the assets are not rate based.

On July 25, 2003, the Utilities Division Staff ("Staff") of the Commission filed a letter stating that the application was found sufficient and classified the applicant as a Class A utility.

By Procedural Order issued August 6, 2003, a Procedural Conference was scheduled for August 13, 2003, and intervention was granted to the Arizonans for Electric Choice and Competition ("AECC"), the Federal Executive Agencies ("FEA"), the Kroger Company ("Kroger"), the Residential Utility Consumer Office ("RUCO"), the Arizona Utility Investors Association, Inc., ("AUIA") and Phelps Dodge Corporation and Phelps Dodge Mining Company ("Phelps Dodge").

By various Procedural Orders, intervention was granted to: the International Brotherhood of Electrical Workers, AFL-CIO, CLC, Local Unions 387, 640 and 769 (collectively, "IBEW"), the Arizona Cogeneration Association/Distributed Generation Association of Arizona ("ACA" or "DEAA"), Panda Gila River, L.P. ("Panda"), Arizona Water Company ("AWC"), Southwest Gas Corporation ("SWG"), Western Resource Advocates ("WRA"), Constellation NewEnergy, Inc.

("CNE"), Strategic Energy, L.L.C. ("SEL"), Dome Valley Energy Partners, LLC ("DVEP"), UniSource Energy Services ("UES"), Arizona Community Action Association ("ACAA"), Arizona Competitive Power Alliance ("Alliance"), the Town of Wickenburg ("Wickenburg")[1], the Arizona Solar Energy Industries Association ("AriSEIA"), the Arizona Association of Retired Persons ("AARP"), Southwest Energy Efficiency Project ("SWEEP"), PPL Sundance, LLC ("PPL Sundance"), PPL Southwest Generation Holdings, LLC ("PPL Southwest"), Southwestern Power Group II, LLC ("SWPG"), Mesquite Power, LLC ("Mesquite") and Bowie Power Station, LLC ("Bowie").

On November 5, 2003, Staff filed a Motion to Consolidate ("Motion") the preliminary inquiry created by Decision No. 65796 and by Procedural Order the Motion was granted, authorizing Staff to include its report in this docket.

II. PRE-SETTLEMENT POSITIONS OF PARTIES

	APS	Staff	RUCO	Settlement Agreement
Revenue requirement	+$175.1 M	-$142.7 M	-$53.6 M	+$75.5 M
Return on Equity	11.5 %	9.0%	9.5%	10.25 %
Debt cost	5.8 %	5.8%	5.8%	5.8%
Capital Structure	50/50	55/45	55/45	55/45
Cost of Capital	8.67 %	7.3%	7.43%	7.8 %
PWEC assets	$848 M	-	-[2]	$700 M

III. SETTLEMENT AGREEMENT

a. Introduction

On August 18, 2004, a Settlement Agreement signed by 22 parties[3] was docketed with the Commission. AWC, SWG, and UES do not oppose the Settlement Agreement, and the AARP made public comment supporting it. The only party opposed to the Commission's adoption of the Settlement Agreement that presented testimony and evidence is the Arizona Cogeneration

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[1] On August 18, 2004, Wickenburg moved to withdraw its intervention.
[2] Phase 1.
[3] APS, ACAA, Alliance, AECC, AriSEIA, AUIA, Bowie, CNE, DVEP, FEA, IBEW, Kroger, Mesquite, Phelps Dodge, PPL Southwest, PPL Sundance, RUCO, SWEEP, SWPG, Staff, SEL, and WRA.

Association/Distributed Generation Association of Arizona.[4]

APS' central objectives in settling were to preserve the company's financial integrity;[5] resolve the issue of asset "bifurcation"; and to determine the company's future public service obligations.

Staff believes that the Settlement Agreement is in the public interest because: it is fair to ratepayers because it precludes inappropriate utility profits and results in just and reasonable rates; it is fair to the utility because it provides revenues necessary to provide reliable electric service along with an opportunity for a reasonable profit; the proposal balances many diverse interests including those of low-income customers, the renewable energy sector, Demand Side Management ("DSM") advocates, merchant generators, and retail energy marketers; it allows APS to rate base the PWEC assets, which are the generating plants originally built by APS' affiliate, PWEC, at a value that is significantly below their book value; potentially anti-competitive effects that may be associated with rate basing the PWEC assets are addressed through a self-build moratorium, a competitive solicitation in 2005, through workshops to address future resource planning and acquisition issues, and by adopting cost-based unbundling for generation and revenue cycle services in the rate design for general service customers, encouraging those customers to shop for competitive services; the Settlement Agreement resolves long, complex litigation by resolving issues associated with prior Commission decisions that are on appeal; the Settlement Agreement facilitates the provision of electric service at the lowest reasonable rates; it provides additional discounts to low-income APS customers, increases funding for advertising these discounts, and increases funding for APS' low-income weatherization program; and because it includes a comprehensive DSM proposal intended to foster the development of new DSM programs while ensuring that the expenditures will be reasonable and subject to appropriate Commission oversight.[6]

RUCO noted that this rate case allowed sufficient opportunity for it to fully audit the Company's cost-of-service study and allowed all parties to be included in the negotiations. RUCO points to the very substantial, nearly universal consensus reached in the Settlement Agreement as

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[4] New Harquahala Generating Company, LLC and Panda made statements objecting to the rate basing of the PWEC assets.

[5] Defined as the ability to attract capital on reasonable terms and earn a reasonable return. Tr. p. 420.

[6] Summary of settlement testimony of Ernest Johnson.

indicating that the public interest has been served. According to RUCO, the "ultimate expression of the agreement having met the Public Interest is the degree to which rate increases have been minimized without jeopardizing the financial integrity of the applicant."[7]

The Alliance's central objective is to continue towards a viable and effective wholesale market into which Alliance members can sell their power. According to the Alliance, there are several key provisions in the Settlement Agreement that accomplish that goal: the restrictions on self-build coupled with the high growth rate in APS' service territory; and the 1,000 megawatt Request for Proposal ("RFP") in 2005. The Settlement Agreement also preserves the financial stability and creditworthiness of the Alliance's target customer – APS.[8]

b. Revenue Requirements

For ratemaking purposes and for purposes of the Settlement Agreement, the parties agree that APS will receive a total increase of $75.5 million over its adjusted 2002 test year ("TY") revenue of $1,791,584,000. This represents an increase in base rates of $67.6 million and a Competition Rules Compliance Charge ("CRCC") surcharge collecting $7.9 million. Pursuant to the Settlement Agreement filed on August 18, 2004, as corrected in the hearing, the Company's fair value rate base ("FVRB") is $5,054,426,000.[9] According to the Settlement Agreement, this revenue increase will allow the Company the opportunity to earn a fair value rate of return of 5.92 percent. According to the Company and Staff, the revenue requirement contained in the Settlement Agreement provides sufficient revenues for APS to provide adequate and reliable service.[10]

c. PWEC Asset Treatment

The Settlement Agreement provides that APS will acquire and rate base generation units owned by PWEC.[11] Those units include: West Phoenix CC-4; West Phoenix CC-5; Saguaro CT-3; Redhawk CC-1; and Redhawk CC-2 ("PWEC assets"). Pursuant to the Settlement Agreement, the

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[7] Summary of settlement testimony of Stephen Ahearn.
[8] Tr. p. 458.
[9] Paragraph 4 to the Settlement Agreement states the FVRB is $6,281,885,000, however, during the hearing, that amount was corrected to $5,054,426,000. Tr. p. 692.
[10] Tr. p. 810.
[11] On November 10, 2004, PWEC filed a letter with the Commission indicating that it would abide by the provisions of the Settlement Agreement that require PWEC to take or refrain from taking any action in order to carry out the intent of the Settlement Agreement.

original cost rate base ("OCRB") of the PWEC assets will be $700 million which is $148 million less than the original cost of the assets as of December 31, 2004. According to the Settlement Agreement, this represents a reasonable estimate of the value of the remaining term of the Track B contract between APS and PWEC.[12] APS agrees to forgo any present or future claims of stranded costs associated with these PWEC assets. According to the Settlement Agreement, APS is required to seek approval of certain aspects of the asset transfer from the Federal Energy Regulatory Commission ("FERC"). APS agreed to file a request for FERC approval within 30 days of the Commission's approval of the Settlement Agreement, and the parties have agreed not to oppose the FERC application. The Settlement Agreement provides for a bridge purchased power agreement ("Bridge PPA") to be implemented once new rates are put in place, until the actual date of the transfer of assets. APS and PWEC will execute a cost-based PPA which will be based on the value of the PWEC assets, and fuel costs and off-system sales revenue will flow into the power supply adjustor ("PSA"). If FERC denies the asset transfer, then the Bridge PPA will become a 30 year PPA, with prices reflecting cost-of-service as if the PWEC assets were rate-based at the $700 million amount in the Settlement Agreement, and with the associated fuel costs and off-system sales revenue flowing through the PSA. The basis point credit established in Decision No. 65796 will continue as long as the debt between APS and PWEC associated with the PWEC assets is outstanding. Credit for amounts deferred after December 31, 2004 will be accounted for in APS' next rate case. The Settlement Agreement also provides that West Phoenix CC-4 and West Phoenix CC-5 will be deemed "local generation" and during must-run conditions, generation from the West Phoenix facilities will be available at FERC-approved cost-of-service prices to electric service providers ("ESPs") serving direct access loads in the Phoenix load pocket.

Treatment of the PWEC assets requires not only a regulatory ratemaking type analysis, but also an analysis of how rate basing these assets fits with the Commission's overall plan for wholesale and retail electric competition in Arizona.

For the last ten years, the Commission has studied, discussed, and deliberated about electric

[12] Docket Nos. E-00000A-02-0051 et al.

competition through workshops, rulemakings, hearings, and open meetings. Several versions of electric competition rules have been adopted, and litigation concerning Commission decisions has been conducted. Throughout this time, the Commission has always maintained its intent to encourage competition in the electric industry. In the wake of the California energy crisis the Commission opened dockets to examine changing industry and market conditions and introspectively analyzed their impact on Arizona's existing rules. The Commission reacted in a measured manner to flawed rules in other jurisdictions and corrected, but did not change, its course.

The Commission continues to support competition as yielding economic and environmental benefits to Arizona consumers. The $148,000,000 discount from book for the rate-based PWEC assets is indicative of these benefits. Recent transactions reflected in the record, including below-cost sales, foreclosures and bankruptcies, establish that the shareholders of the power plants' builders absorbed the costs and bore the brunt of a declining market, rather than Arizona ratepayers. The discounted conveyance of the PWEC assets to APS is further support for this proposition. APS' request and the Settlement Agreement's provision allowing APS to acquire the PWEC assets and put them in rate base raises the issue of whether such action would undermine the Commission's stated intent to encourage retail and wholesale competition. The terms of the Settlement Agreement taken as a whole indicate to us that the answer to that question is "no".

During the hearing on the Settlement Agreement, the parties presented evidence demonstrating that the PWEC acquisition was the most beneficial option for ratepayers. Staff testified that the responses to APS' last formal RFP did not indicate to Staff that the market would provide a superior alternative to the rate basing of the PWEC assets. The testimony indicates that growth in APS' service territory is a minimum of 3 percent per year. APS argued that even with rate basing the PWEC assets, APS' needs would not be met, and it would have to procure additional power to meet the needs of its customers. The Settlement Agreement provides that APS will issue an RFP for an additional 1000 megawatts, thereby giving other market participants an opportunity to compete. The organization created to represent the interests of the merchant community, the Alliance, supports the transfer of assets, because it believes that resolving the broader issues of overall market structure, the self-build guidelines and future RFPs, together with the reduction in litigation risk will further its overall goal of promoting a viable and effective wholesale market. The key provision that the Alliance relies on is the 1,000 megawatt RFP in 2005 that provides a degree of certainty regarding the timing of an initial increment of APS' future needs to be met from the wholesale market. Also, the Alliance believes that opportunities will exist for its members because of the self-build limitation and the high growth rate in Arizona. The proponents of retail competition also support the asset transfer; in large part because APS agrees to forgo any present or future claims of stranded costs associated with the PWEC assets, because rates are unbundled, and because of the treatment of the West Phoenix facilities.

We believe that nothing in the Settlement Agreement prevents the continued development of electric competition. Any potential anti-competitive effects of the asset transfer will be addressed through the competitive solicitations, the self-build moratorium,[13] and Staff's workshops to address future resource planning and acquisition issues. As discussed below, the evidence indicates that the asset transfer captures the benefit of the competitive procurement that took place as a result of the Track B proceeding.

The original cost of the PWEC assets at December 31, 2004 was $848 million. Traditionally, when a utility builds plant, unless there is a finding of imprudency, that portion of the plant that is used and useful is put into rate base and the utility is allowed an opportunity to earn a reasonable rate of return on that investment. This situation is different from the traditional rate case. APS did not build the PWEC assets; they were built by APS' affiliate during a time when the Commission intended APS to divest itself of generation. During the proceeding on APS' financing application, concern was raised that APS and its affiliates took actions that gave it an unfair advantage as compared to its potential competitors. In Decision No. 65796, which granted APS' financing request, we directed Staff to conduct a preliminary inquiry into the issue of APS and its affiliate's compliance with our electric competition rules, Decision No. 61973, and applicable law. The Settlement Agreement provides that the preliminary inquiry will be concluded with no further action by the

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[13] Neither APS nor PWEC will build the Redhawk Units 3 & 4. PWEC's February 2003 self-certification filing with the Commission stated that the two remaining units pursuant to its Certificate of Environmental Compatibility ("CEC") would not be built. Tr. pp. 594-5.

Commission. Accordingly, we make no finding as to why or for whom the PWEC assets were built, and base our resolution of the rate basing issue solely on the merits of the terms of acquisition. We believe that if there were a serious threat to competition, we would hear from those affected, loudly and strongly. Therefore, we were keenly interested in the position of the members of the Alliance, as they are one type of entity that could be harmed. The Alliance supports the acquisition of the PWEC assets by APS. Every person or entity that will be affected by the rate basing of the PWEC assets had the opportunity to participate and present evidence and testimony on this issue. Although two independent power producers made comments objecting to the acquisition without an RFP, neither presented any evidence that demonstrated that competition would be harmed, nor rebutted the testimony and evidence concerning APS' recent RFP.

Initially Staff recommended that the PWEC assets not be rate based, but after analyzing the Company's rebuttal testimony and evidence, agreed that a reduction of $148 million in original cost rate base made the acquisition beneficial to ratepayers. The evidence in the record is substantial that APS' analysis of other options versus rate basing PWEC assets showed that: using an "other build" analysis, rate basing the PWEC assets would cost $300-600 million less than cost to build other plants such as Combustion Turbines ("CT"); using a comparable sales analysis showed that other recent sales had a per kW cost in excess of $527 and the PWEC assets are at $417; when compared to the offers resulting from the recent RFP conducted by APS, the PWEC assets (when valued at the before discount $848 million level) showed benefits of $600-900 million; and using a discounted cash flow analysis the PWEC assets had a savings of $250 million to $1 billion.

As part of the settlement, APS agreed to reflect an original cost rate base value of $700 million, representing a $148 million disallowance. The effect of a reduction in rate base is to immediately reduce the revenue requirement, and to preserve that diminished revenue requirement for the life of the plant.

The analyses showing that the rate basing of the PWEC assets will result in lower rates than other options, together with no showing that such an acquisition would harm the development of a competitive wholesale or retail market indicate that it is reasonable and in the public interest for APS to acquire and rate base the PWEC assets as set forth in the Settlement Agreement.

d. Cost of Capital

The Settlement Agreement adopts a capital structure of 55 percent long-term debt and 45 percent equity for ratemaking purposes. The parties agree that a 10.25 percent return on common equity and a 5.8 percent embedded cost of long-term debt is appropriate.

e. Power Supply Adjustor (PSA)

The Settlement Agreement provides that a PSA be implemented and remain in effect for a minimum of five years, with reviews available during APS' next rate case, or upon APS' filing its report on the PSA four years after rates are implemented in this rate case. Regardless of the review/report, the PSA cannot be abolished until five years have expired. The Settlement Agreement provides that APS will file a plan of administration as part of its tariff filing that describes how the PSA will operate. According to the Settlement Agreement, the PSA will have the following characteristics:

- Includes both fuel and purchased power;
- The adjustor rate will initially be set at zero and will thereafter be reset on April 1 of each year, beginning with April 1, 2006. APS will submit a publicly available report on March 1 showing the calculation of the new rate, which will become effective unless suspended by the Commission;
- Incentive mechanism where APS and its customers share 10 percent and 90 percent, respectively, the costs and savings;
- Bandwidth that limits annual change in adjustor of plus or minus $0.004 per kilowatt hour, with additional recoverable or refundable amounts recorded in balancing account;
- Surcharge possible if balancing account reaches plus or minus $50 million and Commission approves;
- Off-system sales margins credited to PSA balance;
- Recovery of prudent, direct costs of contracts for hedging fuel and purchased power costs;
- Interest on balancing account will accrue based on the one-year nominal Treasury constant maturities rate;
- The Commission or its Staff may review the prudence of fuel and power purchases at any

time;

- The Commission or its Staff may review any calculations associated with the PSA at any time; and
- Any costs flowed through the adjustor are subject to refund if the Commission later determines that the costs were not prudently incurred.

The Settlement Agreement provides that APS shall provide monthly reports to Staff's Compliance Section and to RUCO detailing all calculations related to the PSA, and shall also provide monthly reports to Staff about APS' generating units, power purchases, and fuel purchases. An APS officer must certify under oath that all the information provided in the reports is true and accurate to the best of his or her information and belief. The Settlement Agreement also provides that direct access customers and customers served under rates E-36, SP-1, Solar-1, and Solar-2 are excluded from paying PSA charges. Under the Settlement Agreement, the PSA remains in effect for 5 years, and if after that, the Commission abolishes the PSA, it must provide for any under- or over-recovery and can adjust base rates to reflect costs for fuel and purchased power. The parties agree that a base cost of fuel and purchased power of $.020743 per kWh should be reflected in APS' base rates.

Decision No. 61973 (October 6, 1999) adopting the previous APS settlement, required APS to request, and the Commission to approve, a "power supply adjuster" mechanism to recover the cost of providing power for standard offer and/or provider of last resort customers.

In Decision No. 66567 (November 18, 2003), the Commission approved the concept of a Purchased Power Adjustor ("PPA") which included purchased power costs and did not include the cost of fuel. The Decision noted that the adjustor mechanism approved therein may be modified or eliminated in this rate case. As noted in that Decision, there are advantages and disadvantages to adjustor mechanisms:

Advantages: 1) the reporting requirements and forecasts facilitate utility planning and Staff overview of costs; 2) an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity capital in a rate case and result in lower rates; 3) adjustors can create price signals to consumers, but the effectiveness is reduced considerably when a band is included; 4) adjustors can help reduce the frequency of rate cases; 5) regulatory lag between the incurrence of an expense and its recovery is reduced and generational inequities are also reduced.

Disadvantages: 1) adjustors can reduce incentives to minimize costs; 2) an adjustor that includes fuel or purchased power costs potentially biases capital investment decisions towards those with lower capital costs and higher fuel costs; 3) adjustors create another layer of regulation to rate cases, increasing the cost of regulation to the utility, its customers, and to the Commission; 4) an adjustor can shift a disproportionate proportion of the risk of forced outages and systems operations from shareholders to ratepayers; 5) adjustors result in piecemeal regulation – an adjustor reflects an increase in one expense but ignores offsetting savings in other costs; 6) adjustors are complex and often difficult for analysts to read and interpret, and are difficult to explain to customers; 7) proper monitoring of adjustor filings and audits require the devotion of significant Staff resources; and 8) rates are less stable, resulting in rates changing frequently, making it difficult for customers to plan energy consumption and the purchase of energy consuming appliances.

Although we recently approved the concept of a PSA, we are concerned about the PSA as proposed in the Settlement Agreement. The benefits of this PSA are that over time, the utility's earnings will be stabilized, thereby preserving its financial integrity and in the longer term, improve the likelihood that the company will attract capital on reasonable terms, to the benefit of ratepayers. Further, as part of the negotiations, the parties were able to agree on a lower overall revenue increase because a PSA was to be implemented. AECC pointed out that if an adjustor remains in effect for long enough, it becomes a credit, and therefore, the PSA should remain in effect for five years.[14]

The disadvantages are real and significant – from a customer standpoint, adjustors are difficult to understand and they can cause annual price increases. From a regulatory standpoint, they require significant Commission staff resources to properly monitor filings, costs, and compliance and to respond to consumer inquiries and complaints. The most significant change that will occur with a PSA is the shifting of the risk that fuel costs will increase above the base rates established in the Settlement Agreement. Currently, if fuel costs or any other costs rise above the level embedded in

[14] Tr. p. 1249.

the existing rate structure, the company's shareholders feel the impact. Likewise, if the costs decrease, the shareholders benefit. Under a PSA, the shareholders are insulated from the change in costs, because now the ratepayers are obligated to pay the additional costs. Further, the testimony was clear that costs are going to be increasing, not only because natural gas prices will increase, but also because APS' "mix" of fuel will change as growth occurs.[15] That mix will include an increasing amount of natural gas to supply the new generation. When compared to APS' other fuel sources such as nuclear or coal, natural gas is a substantially higher cost fuel. So here, the PSA will not only be collecting additional revenues due to fuel price increases, but also increases due to growth that is met with generation from a high cost fuel.[16]

Although the Settlement Agreement provides that APS will increase its demand side management and renewables, and we agree that those resources are increasingly important, they will not likely have a significant ameliorating cost impact in the near future. We disagree with the parties that a 90/10 sharing is sufficient incentive for APS to continue to effectively hedge its natural gas costs. Going from a 100 percent at-risk position to 10 percent at-risk almost seems like a "free pass," especially when a revenue increase is added. Although the Settlement Agreement provides that all costs will be subject to review for prudency before they can be recovered, prudency reviews, especially transactions in the wholesale market, can be difficult to conduct after the fact. Although we have confidence in our Staff's ability to conduct prudency reviews, we do not believe they provide as much incentive to APS on the front end to hedge costs as exists today without a PSA. The band-width limit will help limit drastic increases, but ultimately, APS will be able to recover all the costs from ratepayers.[17]

Accordingly, for these reasons, we believe that provisions of the PSA need to be modified to protect the ratepayers. We agree that the use of an adjustor when fuel costs are volatile prevents a

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[15] As growth occurs, the per unit cost of fuel will increase. Tr. p. 1238. Currently, nuclear is 32 percent of sales and represents 7.4 percent of the costs of generation; coal is 45 percent of sales and 29.7 percent of generation costs; natural gas is 18 percent of sales and 47.4 percent of generation costs; and purchased power is 5 percent of sales and 15.5 percent of generation costs. Tr. p. 1257. In five years, natural gas is expected to be 29-30 percent of sales. TR. p. 1258.

[16] See discussion Tr. p. 1259, PSA will always be increasing.

[17] Staff's late-filed exhibit S-35 filed December 14, 2004 in response to a request from Commissioner Mundell to extrapolate the effects of the PSA over several years, contained an error and on March 9, 2005, Staff filed a corrected exhibit.

utility's financial condition from deteriorating. We are less inclined, however, to adopt an adjustor as a way to keep pace with load growth. Although APS' rebuttal testimony indicated that its fixed costs would increase in relation to its load growth, we are concerned about the potential for single-issue ratemaking and whether APS' fixed costs will increase in the same proportion as its fuel costs. According to the late-filed exhibits, the majority of the increased fuel costs are caused by increased load growth, rather than price volatility in fuel. In effect, the adjustor as designed provides annual step increases in rates. We believe APS must have an incentive to file a rate case so that we can determine the accuracy of its assertion about expenses. Therefore, we will adopt an adjustor that collects or refunds the annual fuel costs that differ from the base year level. However, we will limit the adjustor to 4 mil from the base level over the entire term of the PSA and will cap the balancing account to an aggregate amount of $100 million. Should the Company seek to recover or refund a bank balance pursuant to Paragraph 19E of the Settlement Agreement, the timing and manner of recovery or refund of that existing bank balance will be addressed at such time. In no event shall the Company allow the bank balance to reach $100 million prior to seeking recovery or refund. Following a proceeding to recover or refund a bank balance between $50 million and $100 million, the bank balance shall be reset to zero unless otherwise ordered by the Commission.

Further, we will limit the amount of "annual net fuel and purchased power costs" (as shown in Staff Exhibit 23)[18] that can be used to calculate the annual PSA to no more than $776,200,000. Any fuel or purchased power costs above that level will not be recovered from ratepayers. We believe that this "cap" on fuel and purchased power costs will further encourage APS to manage its costs, and will help to prevent large account balances from occurring in one year. Because the PSA actually adjusts for growth, putting a "cap" on recovery of these costs will help insure that APS will file a rate application when necessary.[19] Since there is no moratorium on filing a rate case, APS can file a rate case to reset base rates if it deems it necessary because that cap is reached. Further, although the Settlement Agreement provides that the PSA will be in effect for 5 years, if APS files a rate case

[18] For example, under "Average Usage Scenario One", the line reads "Annual Net Fuel and Purchased Power Costs: $524,600,000."

[19] See S-35 filed March 9, 2005, Scenario 11A – even when the price of gas remains constant, the PSA adjustor increases, because the adjustor uses total costs (not price) which reflects the growth which is being met by the higher priced fuel, natural gas.

prior to the expiration of that 5 year term or if we find that APS has not complied with the terms of the PSA, we believe that the Commission should be able to eliminate the PSA if appropriate. Finally, we will not allow any fuel costs from 2005 that were incurred prior to the effective date of this Decision to be included in the calculation of the PSA implemented in 2006. We believe that these additional provisions to the PSA will help to lessen the detrimental impact to ratepayers of this change to an adjustor mechanism.

Implementing an adjustor mechanism will have a significant impact upon both APS and its customers. For many years now, in their monthly bills, APS customers have paid rates that reflect the costs that APS is allowed to recover for providing that service. With the implementation of an adjustor, those ratepayers will be obligated to pay additional amounts for service they received in the previous year. This represents a major shift in responsibility for increased costs, from APS and its shareholders to ratepayers. According to APS, such a shift is necessary for the company to preserve its financial integrity.

Although the parties submitted a written statement describing the calculation of off-system sales in response to a question from Commissioner Mundell, we are concerned that the method may not capture the full margin on each sale.[20] Additionally, we want to make sure that off-system sales are not being made below costs – Staff needs to study ways to insure that these off-system sales margins are being determined accurately and that ratepayers are receiving the full 90 percent of the benefits. Accordingly, we will direct Staff to establish a method that accurately reflects the appropriate fuel costs and revenue for off-system sales, so that the full margin is known and properly accounted for. Within three years of the effective date of this Decision, Staff shall commence a procurement review of APS' fuel, purchased power, generating practices and off-system sales practices.

In response to Commissioner Gleason's suggestion to set up a webpage explaining its bill, APS indicated that it was planning to have a new bill format, and agreed to also set up a website to

[20] For example, a wholesale contract may have an embedded cost of fuel built into the price of the energy that is different from the cost of fuel use to generate the energy – if the "sales margin" is defined as the difference between the actual cost of fuel and the revenue from the sale, the true sales margin will not be captured. We also take administrative notice of FERC Docket No. PA04-11-000 and the FERC's December 16, 2004 Order Approving Audit Reports and Directing Compliance Actions, specifically relating to treatment of off-system sales.

explain the bills. Because the implementation of an adjustor will be a major change in the way that customers are billed, we believe that APS should also implement a customer education program explaining how its PSA will work and we will order APS to maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs. It is important that the customer education program be implemented in a timely fashion, before this summer. APS needs to make its customers aware that with the implementation of an adjustor, ratepayers will be obligated to pay additional amounts for service they received in the previous year. It is essential, and only fair, that customers understand that their usage this summer can have an effect on their electric bills the following year.

Because we are concerned about the impact of the PSA on low-income customers, the PSA shall not apply to the bills of individuals who are enrolled in the Company's Energy Support program. Finally, given our concerns and the modifications we require to the PSA, we will require the parties to the Settlement Agreement to submit a PSA Plan of Administration that reflects the determinations in this Decision, for our approval.

f. Depreciation

The Settlement Agreement adopts Staff's recommended service lives, and Appendix A to the Settlement Agreement sets forth the remaining service lives, net salvage allowance, annual depreciation rates, and reserve allocation for each category of APS depreciable property as agreed to by the parties. The parties agree that the Statement of Financial Accounting Standards ("SFAS") 143 will not be adopted for ratemaking purposes.

g. $234 Million Write-Off

The Settlement Agreement provides that APS will not recover the $234 million write-off attributable to Decision No. 61973 in this case, nor shall APS seek to recover the write-off in any subsequent proceeding. The ESP and large consumer witnesses testified that this provision was critical to the development of flourishing retail markets and will help direct access service from being undercut by future stranded costs claims.

h. Demand Side Management ("DSM")

Demand-side management ("DSM") is "the planning, implementation, and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand (kW), and to reduce energy consumption (kWh) in a cost-effective manner."[21]

DSM is addressed in three areas of the Settlement Agreement: in the funding, programs, plans and reporting provisions; in the study of rate design modifications; and in the competitive procurement process.

Funding for DSM comes in both base rates ($10 million per year) and through implementation of an adjustor (average of $6 million per year).[22] DSM funding will be used for "approved eligible DSM-related items," including "energy-efficiency DSM programs,"[23] a performance incentive,[24] and low income bill assistance.[25] APS is obligated to spend $13 million in 2005 on DSM projects.[26]

Appendix B to the Settlement Agreement is a preliminary plan ("Preliminary Plan") for eligible DSM-related items for 2005. The Preliminary Plan includes $6.9 million for commercial, industrial, and small business customer programs, including new construction, retrofitting existing facilities, training and education, design assistance, and financial incentives; it includes $6.2 million for residential customers, including new construction and existing homes and HVAC, education, training, expanded low income weatherization, and bill assistance; $1.3 million for measurement, evaluation, and research; and $1.6 million for performance incentive.[27] Within 120 days of the Commission's approval of the Preliminary Plan, APS will, with input and assistance from the collaborative working group, submit a Final Plan for Commission approval.

In order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

The adjustor will collect DSM costs that are above the $10 million annual level included in

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[21] Direct testimony of Barbara Keene, February 3, 2004.
[22] APS will spend at least $48 million during calendar years 2005-2007.
[23] "Energy-efficient DSM" is defined as "the planning, implementation and evaluation of programs that reduce the use of electricity by means of energy-efficiency products, services, or practices." Settlement Agreement par. 40.
[24] Id. par. 45.
[25] Id. par. 42.
[26] Tr. p. 969.
[27] APS' share of DSM net economic benefits, capped at 10 percent of total DSM expenditures.

base rates. The adjustor rate will initially be set at zero, and will be adjusted yearly on March 1, based upon the account balance and the appropriate kWh or kW charge. The DSM adjustor will apply to both standard offer and direct access customers.

The Settlement Agreement does not provide for the recovery of net lost revenues. The Settlement Agreement provides that if during 2005 through 2007, APS does not spend at least $30 million of the base rate allowance for approved and eligible DSM-related items; the unspent amount will be credited to the account balance for the DSM adjustor.

On residential customers' bills, the DSM adjustor will be combined with the EPS adjustor and be called an "Environmental Benefits Surcharge."[28] As part of its tariff compliance filing, within 60 days of this Decision, APS must file a Plan of Administration for Staff review and approval.

Pursuant to the Settlement Agreement, APS is required to "implement and maintain a collaborative DSM working group to solicit and facilitate stakeholder input, advise APS on program implementation, develop future DSM programs, and review DSM program performance."[29] The working group will review the plans, but APS is responsible for demonstrating appropriateness of its programs to the Commission. APS is required to conduct a study to review and evaluate whether large customers should be allowed to self-direct DSM investments and file the study within one year. APS is also required to study rate designs that encourage energy efficiency, discourage wasteful and uneconomic use of energy, and reduce peak demand. The plan for the study and analysis of rate design modifications must be presented to the collaborative DSM working group within 90 days, and APS must submit to the Commission the final results as part of its next rate case, or within 15 months of this Decision, whichever is first. APS is required to develop and propose appropriate rate design modifications. Additionally, APS is required to file mid-year and end-year reports on each DSM program. All DSM year-end reports filed at the Commission by APS must be certified by an Officer of the Company.

Pursuant to the Settlement Agreement, APS is to invite DSM resources to participate in its RFP and other competitive solicitations, and must evaluate them in a consistent and comparable

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[28] Settlement Agreement par. 50.
[29] Id. par. 54.

manner.

SWEEP supports the DSM provisions in the Settlement Agreement. Although it originally recommended that the Commission should substantially increase energy efficiency by setting target goals of 7 percent of total energy resources needed to meet retail load in 2010 from energy efficiency and 17 percent in 2020, it agreed that the Settlement Agreement's requirement of DSM funding is reasonable and justified given the cost-effective benefits that will be achieved. SWEEP believes that the level of funding in the Settlement Agreement is a valuable and meaningful step towards encouraging and supporting energy efficiency for APS customers, especially since the Commission can approve additional DSM program funding through the adjustment mechanism.

In response to questioning from Commissioner Spitzer, the witness for SWEEP testified that DSM is the most efficient way to mitigate market and fuel price increases and it reduces customer vulnerability to price volatility, by reducing the need for new power plant construction and new transmission lines.[30] Even customers who do not participate in the DSM programs will benefit, both from an economic perspective as well as from the environmental and health standpoint.[31] The Preliminary DSM Plan attached as Exhibit B to the Settlement Agreement is a good start towards developing cost-effective DSM programs. However, we are concerned that our approval of the Settlement Agreement and Exhibit B may result in stakeholders focusing too narrowly when attempting to comply with the DSM goals of this Order. Particularly, we note that there are no demand response programs included in Exhibit B. Given the response by APS' customers to last summer's outage as discussed by Commissioner Hatch-Miller,[32] it is clear that when proper signals are given, customers will respond by reducing their demand.

We also think it is clear that the traditional demand response programs that define "off-peak" hours as between 9:00 p.m. to 9:00 a.m. are ineffective in creating an incentive to residential ratepayers to shift their electricity consumption to "off peak" hours. Common sense indicates that a substantial number of ratepayers cannot or are not able to take advantage of such programs as 9:00 p.m. is an unrealistic time to commence the "off peak" period because most ratepayers are either

[30] Tr. p. 877.
[31] Tr. p. 930.
[32] See discussion Tr. pp. 1384-1394.

asleep or preparing to sleep at that time.[33] Further, the start time begins many hours after the actual peak has subsided. Finally, the inconvenience of a 9:00 p.m. start time assures that the demand response to "off peak" hours and programs is miscalculated. Therefore, in an effort to expedite APS' addressing demand response programs, we will order APS to file additional time-of-use programs that are similar to the Time Advantage and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

We believe that it would be beneficial, perhaps in conjunction with the rate design time-of-use study and the use of "advanced" or "smart" meters, to evaluate and implement programs designed to reduce APS' summer peak demand. Accordingly, we will encourage submission of such DSM programs.

i. <u>Environmental Portfolio Standard and other Renewables Programs</u>

The Settlement Agreement addresses renewable energy in three areas: a special renewable energy solicitation; the environmental portfolio standard ("EPS") and in the competitive procurement of power.

The Settlement Agreement requires APS to issue a special RFP in 2005 seeking at least 100 MW and at least 250,000 MWh per year of renewable energy resources including solar, biomass/biogas, wind, small hydro (under 10 MW), hydrogen (other than from natural gas) or geothermal for delivery beginning in 2006. In order to take advantage of any available federal tax credits for renewable energy production, APS should issue the 100 MW RFP no later than May 15, 2005. APS also will seek to acquire at least ten percent of its annual incremental peak capacity needs from renewable resources. Among other requirements, the renewable resources must be no more costly than 125 percent of the reasonably estimated market price of conventional resource alternatives and APS can acquire out-of-state resources to meet the goal if sufficient in-state qualified bids are not received. However, if APS determines that it cannot meet this requirement through in-state resources, it must bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

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[33] We do not need a study, workshop or to evaluate the proposed test demand programs to convince us regarding residential demand programs in this matter.

The Settlement Agreement also provides that renewable resources acquired through the special RFP or future solicitations shall be subject to the Commission's customary prudence review. And while the Settlement Agreement further stipulates that a renewable resource purchase shall not be found imprudent solely because the cost of the renewable resource exceeds market price, we stipulate conversely that a renewable resource purchase shall not be rendered prudent solely by virtue of the resource's cost being below 125 percent of market price.

The special RFP does not displace APS' requirements under the EPS. APS will continue to collect $6 million annually in base rates and the existing EPS surcharge, which provided $6.5 million during the test year, will be converted to an adjustment mechanism, which will allow for Commission-approved changes to APS' EPS funding.

The Settlement Agreement does not alter the existing EPS or the current level of funding, but it changes the EPS surcharge into an adjustor so that the Commission has the flexibility to change funding levels and rates in the future. APS' current rates and surcharge total $12.5 million and pursuant to the Settlement Agreement, $6 million of this amount will be recovered in base rates and $6.5 million in the EPS adjustor.

Under the Settlement Agreement, APS will allow and encourage all renewable resources to participate in its competitive power procurement.

In response to a request from Commissioner Spitzer, several parties filed late-filed exhibits concerning the recently enacted American Jobs Creation Act of 2004. According to APS, the Act provides for a domestic production deduction for its generation activities, and also extends renewable electricity production credits through 2005 and expands the types of renewable resources eligible for the credits.[34] In its December 10, 2004 response, WRA stated that "renewable energy appears to be at a disadvantage relative to gas-fired generation because the tax burden tends to fall more heavily on capital intensive projects such as renewable energy generation. Therefore, such tax burden differentials may add further support for the preference for renewable energy in the settlement agreement and for production tax credits as means to 'level the playing field' between gas-fired

[34] Previously, only wind, closed-loop biomass and poultry waste were included, and now open-loop biomass, geothermal energy, solar energy, small irrigation power, and municipal solid waste are included as qualified energy resources.

resources and renewable energy."

j. <u>Competitive Procurement of Power</u>

The Settlement Agreement provides that APS will issue an RFP or other competitive solicitation(s) in 2005 seeking long-term resources of not less than 1000 MW for 2007 and beyond. "Long-term" resource is defined as acquisition of a generating facility or an interest in one, or any PPA of 5 years or longer. No APS affiliate will participate in this RFP/solicitation, and in the future will not participate unless an independent monitor is appointed. Further, APS will not self-build any facility with an in-service date prior to January 1, 2015, unless expressly authorized by the Commission. As defined in the Settlement Agreement, "self-build" does not include the acquisition of a generating unit or interest in one from a non-affiliated merchant or utility generator, the acquisition of temporary generation needed for system reliability, distributed generation of less than 50 MW per location, renewable resources, or the up-rating of APS generation.

We generally agree that the self-build moratorium proposed in the Agreement is useful for addressing the potentially anti-competitive effects that may be associated with rate-basing the PWEC assets. However, to fully realize the benefits of the moratorium for that purpose, the moratorium should apply to the acquisition of a generating unit or interest in one from any merchant or utility generator, as well as to building new units. Accordingly, we will modify the definition of "self-build" to include the acquisition of a generating unit or interest in a generating unit from any merchant or utility generator. Consistent with the definition in the Settlement Agreement, "self-build" will not include the acquisition of temporary generation needed for system reliability, distributed generation of less than fifty MW per location, renewable resources, or up-rating of APS generation, which up-rating shall not include the installation of new units.

Similarly, we will require APS to obtain the Commission's expressed approval for APS' acquisition of any generating facility or interest in a generating facility pursuant to a RFP or other competitive solicitation[35] issued before January 1, 2015. Our determination herein should not be construed as signaling in any manner the ultimate regulatory treatment that can or will be accorded to

[35] Competitive solicitation includes a RFP issued pursuant to Paragraph 78 of the Settlement Agreement or any solicitation issued by APS in using its Secondary Procurement Protocol pursuant to Paragraph 80 of the Settlement Agreement.

any generating facility or interest in any generating facility ultimately acquired by APS. APS will continue to use its Secondary Procurement Protocol except as modified by the Settlement Agreement or by Commission decision. The Commission's Staff will schedule workshops on resource planning, focusing on developing needed infrastructure and a flexible, timely, and fair competitive procurement process. As discussed above, the rate basing of PWEC assets, at a discount, should not be construed as an abandonment of competition by this Commission. The industry-wide question, "how will new generation be built and by whom?", is particularly trenchant in Arizona due to high forecast growth in customer load. The self-build moratorium agreed to by APS is consistent with the Commission's support for competitive wholesale electricity markets.

The workshops conducted by Staff on the development of needed infrastructure shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations. APS' aging coal fired plants face an increasingly emissions regulated future which may require sizeable investments to improve emissions control performance.

By integrating solar generation with the existing generation and transmission infrastructure at coal fired facilities, it may be possible to create synergies that take advantage of existing site infrastructure to lower the cost of building and operating solar electric generation, while reducing the environmental impact of coal fired generation. Generation from a solar electric project will add fuel-free, net-plant energy output resulting in environmental benefits and lower energy specific water usage. A long-term benefit of such a strategy would be that after all life extension measures are exhausted for the fueled power complexes, there will be many decades of useful life remaining in the transmission assets serving these sites. These valuable assets could be utilized by emission and water free solar generation built incrementally over the next decades in the expansive buffer zone property around many of the existing coal plants.

k. **Regulatory Issues**

In the Settlement Agreement, the parties acknowledge that APS has the obligation to plan for and serve all customers in its certificated service area and to recognize through its planning, the existence of any Commission direct access program and the potential for future direct access customers. Any change in retail access as well as the resale by APS and other Affected Utilities of Revenue Cycle Services to ESPs will be addressed through the Electric Competition Advisory Group ("ECAG") or similar process. The parties acknowledge that APS may join a FERC-approved Regional Transmission Organization ("RTO") or entity and may participate in those activities without further order or authorization from the Commission.

l. **Competition Rules Compliance Charge ("CRCC")**

Included in the total test year revenue requirement is approximately $8 million for the Competition Rules Compliance Charge. APS will recover $47.7 million plus interest through a CRCC of $0.000338/kWh over a collection period of 5 years. When that amount is collected, the CRCC will immediately terminate, and if the amount is under or over recovered, then APS must file an application for the appropriate remedy.

m. **Low Income Programs**

APS will increase funding for marketing its E-3 and E-4 tariffs to a total of $150,000 as set forth in the Settlement Agreement. The parties' intent is to insulate eligible low income customers from the effects of the rate increase resulting from the Settlement Agreement. On December 17, 2004, the ACAA filed a response to Commissioner Mayes' question about automatic enrollment in utility discount programs, indicating that they have initiated a discussion with the Arizona Department of Economic Security ("DES") to facilitate the automatic enrollment in utility discount programs, as well as other agency managed programs. ACAA is in the process of adding the utility discount application forms to its website, which will allow the form to be sent electronically to the appropriate entity for processing. Concerning marketing efforts, ACAA stated that it engages in various outreach efforts throughout the state, providing information about the E-3 discount program available through APS. ACAA indicated that DES is currently charged with the official marketing of the program, but there is currently no affirmative marketing of the program "as their resources are severely limited." Also in response to Commissioner Mayes' request, APS filed information concerning its low income programs. APS stated that it has renewed its conversations with DES and ACAA, requesting feedback on increasing participation through automated signup for the E-3 and E-4 programs. Both agencies expressed interest and APS states that it will continue to work with both agencies to determine the efficiency and practicality of such a streamlined approach.

The Commission believes that APS should work to make its low-income assistance programs widely available, including to Native Americans living inside the Company's service territory. Within six months of the effective date of this Order, APS shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance programs. The plan should be filed with the Commission and made available to Tribal authorities within APS' service territory.

n. Returning Customer Direct Access Charge ("RCDAC")

The Settlement Agreement provides that APS can recover from Direct Access customers the additional cost that would otherwise be imposed on other Standard Offer customers if and when the former return to Standard Offer from their competitive suppliers. The RCDAC shall not last longer than 12 months for any individual customer. The charge will apply only to individual customers or aggregated groups of 3 MW or greater who do not provide APS with one year's advance notice of intent to return to Standard Offer service. APS will file a Plan of Administration as part of its tariff compliance filing.

o. Service Schedule Changes

The Settlement Agreement adopts several of APS' proposed changes to service schedules, including Schedule 3, but with the retention of the 1,000 foot construction allowance for individual residential customers and also with any individual residential advances of costs being refundable. Several APS customers made public comment about the line extension policy and how it has not been modified in a long time. We will direct Staff to work with APS to review its line extension policy and determine whether the construction allowance should be modified.

p. Nuclear Decommissioning

The decommissioning costs as recommended by APS are adopted as set forth in Appendix I to the Settlement Agreement.

q. Transmission Cost Adjustor ("TCA")

The Settlement Agreement establishes a transmission cost adjustor ("TCA") to ensure that any potential direct access customers pay the same for transmission as Standard Offer customers.

The TCA is limited to recovery of costs associated with changes in APS' open access transmission tariff ("OATT") or equivalent tariff. The TCA goes into effect when the transmission component of retail rates exceeds the test year base amount of $0.00476[36] per kWh by 5 percent and APS obtains Commission approval of a TCA rate.

r. Distributed Generation

Generally, distributed generation is small-scale power generation units strategically located near customers and load centers. According to the ACA/DEAA, the benefits of distributed energy systems include: greater grid reliability; increased grid stability (voltage support along transmission lines); increased system efficiency (reduction in transmission line losses); increased efficiency; flexibility; decreased pressure on natural gas (demand and cost); leverage of resources; and sustainable installations.

The Settlement Agreement provides that Staff shall schedule workshops to consider outstanding issues affecting distributed generation and shall refer to the results of the prior distributed generation workshops for issues to study.

ACA/DEAA presented its objectives at hearing as follows: a DG workshop with strong Staff leadership; clear goals, ground rules, milestones, and deadlines; participants with authority; continuing reports to ACC and management; and a process to bring contested issues to the Commission for resolution. None of the proponents of the Settlement Agreement oppose Commission adoption of these objectives.

In its post-hearing brief, ACA/DEAA listed the following guidelines as "overriding criteria": 1) rates must be fair; 2) rates should be designed to send as efficient as possible pricing signals to consumers; 3) impediments to customer choices, such as unnecessarily difficult and expensive interconnection to the grid, should be eliminated to the maximum extent possible; 4) all generators should be treated fairly – large and small; and 5) proposals, if implemented, should not interfere with the Commission's public policy goals. ACA/DEAA made 3 recommendations: 1) Rate Design – the Commission should adopt an experimental rate for partial requirement customers. The proposal

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[36] Paragraph 106 of the Settlement Agreement contains a typo; the amount "$0.000476" should actually be "$0.00476," Tr. p. 1168.

would mimic SRP's E-32 rate, which includes time of day rates and summer/winter rates. ACA/DEAA proposed to limit participation to 50 MWs of new customer load each year for 5 years – both generation and supplemental load. It appears that this is the first alternative rate schedule that ACA/DEAA has proposed, and no party has had an opportunity to evaluate and comment on the proposal. Accordingly, we decline to adopt the proposal in this docket, but we believe that this proposal may be a good starting point for discussion in the DG workshop.

ACA/DEAA further recommended that the Texas standard is best suited for application to the APS system and that the provisions of California rule 21 would serve as a second choice for DG standards in Arizona. ACA/DEAA also recommended that the Commission consider a program to install self generation to reduce the electricity on the power grid. We believe that both of these recommendations should also be discussed and developed during the course of the workshop.

The proponents of the Settlement Agreement recommend that specific issues concerning DG should be addressed in workshops devoted to distributed generation. Paragraphs 108 and 109 direct Staff to schedule workshops to address outstanding DG issues. They believe that such a process would use the work done in previous workshops and would also address the technical aspects of connecting distributed generation in a way that would apply to all regulated utilities in Arizona. To be successful, the process would require a strict timetable for producing recommendations for the Commission's consideration. The proponents argue that Schedule E-32 should not be redesigned to meet the specialized needs of partial requirements service, but that the rate design for partial requirements service should be addressed in the workshop. Approximately 95,000 full requirement customers receive service under Schedule E-32, and according to the proponents, it is an integral part of the Settlement Agreement. The proponents believe that ACA/DEAA's proposal to put the rate increase in the energy portion would create a massive subsidy from higher load factor customers to lower load factor customers. The demand related charges are necessary for pricing the capacity related costs of the APS system for the full requirement customers. The proponents argue that DG requires partial requirement service – which is a very specialized product that includes maintenance power, standby power, and supplemental power – and it should have its own rate, which can be addressed in the proposed DG workshop.

We agree with ACA/DEAA that DG can have significant benefits to APS and to its ratepayers and we want to encourage the growth of DG that can provide those benefits. Additionally, we find some of the suggestions made in ACA/DEAA's post hearing brief persuasive. However, our decision is rooted in the record made in this case, and those suggestions were not fully delineated, nor subjected to cross examination at the Hearing. At this point, we agree with the participants that the E-32 schedule should not be modified to accommodate the particular needs associated with DG. Therefore, we believe that the parties should address the issue of an appropriate rate schedule for DG during the workshop process, and direct the parties to develop a schedule that is designed particularly for DG customers. Further, we direct the parties to begin the process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

s. <u>Bark Beetle Remediation</u>

APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed the test year levels of tree and brush control. In the next rate case, the Commission will determine the reasonableness, prudence, and allocation of the costs, and will determine the appropriate amortization period.

t. <u>Rate Design</u>

Attached to the Settlement Agreement is Appendix J, which sets forth the rates adopted in the Settlement Agreement. The rates are designed to permit APS to recover an additional $67.5 million in base revenues, including an additional 3.94 percent for the residential rate class and a 3.57 percent increase for the general service rate class. The rates were designed to move toward costs and remove subsidizations, thereby promoting equity among customers. The base rates will also permit cost-based unbundling of distribution and revenue cycle services, including metering, and meter reading and billing. The parties believe that this will give appropriate price signals necessary for shopping. APS will continue on-peak and off-peak rates for winter billing for all residential time-of-use customers under Schedules ET-1 and ECT-1R. Within 180 days APS will submit a study to Staff that examines other ways APS can implement more flexibility in changing APS' on- and off-peak time periods and other time-of-use characteristics, making those periods more reflective of actual system peak time periods. APS shall also include in the aforementioned study a cost-benefit analysis of Surepay, APS' automatic payment program. The Company is to examine the cost effectiveness of the program and to explore the possibility of offering a discount to those customer who participate in Surepay. The Settlement Agreement adopts APS' proposed experimental time-of-use periods for ET-1 and ECT-1R. For general service customers, the existing on-peak time periods will remain the same and the summer rate period will begin in May and conclude in October. The general service rate schedules will also permit cost-based unbundling of generation and revenue cycle services and will be differentiated by voltage levels. An additional primary service discount of $2.74/kW for military base customers served directly from APS substations will be adopted. The Settlement Agreement modifies Schedule E-32 in order to simplify the design, make it more cost-based, and to smooth out the rate impact across customers of varying sizes within the rate schedule. Changes include the addition of an energy block for customers with loads under 20 kW and an additional demand billing block for customers with loads greater than 100 kW. A time-of-use option will also be available to E-32 customers. Testimony was offered at the hearing that there was an inadvertent omission in Appendix J to the Settlement Agreement for Rate E-32-TOU in that the delivery-related demand charge for Rate E-32-TOU should have been reduced after the first 100 kW of demand for residual off-peak demand[37] and that the initial rate block for residual off-peak delivery should be applied only to the first 100kW of combined on-peak and residual off-peak demand. We will, therefore, direct APS to modify Rate E-32-TOU in accordance with these changes in its compliance filings. As discussed above, ACA/DEAA objected to the company's E-32 schedule. One of ACA/DEAA's concern was the almost doubling of the demand charge. The Commission has open dockets involving APS' metering and bill estimation procedures, including the estimation of demand. Although we are not resolving those issues in this rate case, we are concerned that APS properly meter, read meters and bill its customers timely and accurately.[38] It is imperative, especially given

[37] Instead of remaining at the initial level of $7.722 per kW-month, after the first 100 kW of demand, the unbundled residual off-peak demand charge for delivery at Secondary voltage will be reduced to $3.497; after the first 100kW of demand, the unbundled residual off-peak demand charge for delivery at Primary voltage will be reduced to $2.877, with both of these changes incorporated into the bundled rate as well.

[38] Also, we note that apparently APS is deleting a bill estimation procedure for EC-1 and ECT-1R. It is not clear whether these are the tariffs that Staff has alleged APS has not been following, but nothing in this Decision will affect our ability to make findings in Docket Nos. E-01345A-04-0657, et al. or impose any appropriate fines, sanctions, or remedies in those dockets.

the increase in the demand charge, that APS reduce the instances where it estimates demand.

In a response (dated August 18, 2004) to a question from Commissioner Mundell regarding the break-over points for tiered rates, the parties to the Settlement Agreement indicated that rate E-12 has the most customers. The response also stated that the average use by a customer on rate E-12 is 770 kWh per month. Rate E-12 has three tiers with break-over points at 400 kWh per month and 800 kWh per month. Paragraph 57 of the Settlement Agreement requires APS to conduct a rate design study analyzing rate design modifications to promote energy efficiency, conservation, and reduce peak demand. As part of the study, we will require that one of the rate design modifications that APS shall investigate is to lower the first break-over point in rate E-12 to 350 kWh per month and lower the second break-over point to 750 kWh per month. In addition, the charge (rate) per kWh in the first tier (less than 350 kWh per month) should be lowered, while the rate for the third tier (over 750 kWh per month) should be raised. We will require that APS propose this type of rate design, or something very similar, for rate E-12 in its next rate case. We believe this type rate design, coupled with the DSM measures outlined in this Order, will encourage customers, especially high-use customers, to conserve energy (thereby lowering overall demand) and/or move to time-of-use rates (thereby lowering peak demand). If APS or any party to the next APS rate case believes this type rate design would be detrimental to APS and/or its customers, that party shall provide a detailed explanation and examples as to how and why this type rate design would be detrimental.

Several schedules are "frozen" and APS will provide notice approved by Staff to those customers that those rates will be eliminated in APS' next rate case. Such notice will be provided at the conclusion of this docket and at the time that APS files its next rate case.

u. <u>Litigation and other issues</u>

The Settlement Agreement provides that APS will dismiss with prejudice all appeals of Decision No. 65154, the Track A Order, and APS and its affiliates will dismiss litigation related to Decision Nos. 65154 and 61973 and/or any alleged breach of contract, and APS and its affiliates shall forgo any claim that APS, PWEC, Pinnacle West Capital Corporation or any of APS' affiliates were harmed by Decision No. 65154, and the Preliminary Inquiry ordered in Decision No. 65796 shall be concluded with no further action by the Commission, once the Settlement Agreement is approved in accordance with Section XXI of the Settlement Agreement by a Commission Decision that is final and no longer subject to judicial review.

The Commission is also concerned that service reliability on rural Tribal lands has become degraded. Therefore, within six months of the effective date of this Order, APS should compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas. Moreover, APS shall participate in any future dockets related to enhancing reliability statewide.

v. Summary

This Settlement Agreement resolves numerous significant, complex, and conflicting issues affecting many parties with very different perspectives and interests. As with every settlement, the give and take nature of negotiations ends up with a product that no one party initially proposed. The key question when deciding whether to approve such a settlement is whether the end result resolves the important issues fairly and reasonably when taken together as a whole, and in such a way that will promote the public interest. We believe that the Settlement Agreement reached by these 22 parties, with the modifications that we make herein, reaches such a result. Our agreement to rate base the PWEC assets does not mean that we are retreating from our commitment to encourage the development of competition, and we expect APS and its affiliates to fully comply with all the pro-competition requirements in the Settlement Agreement and other Commission decisions and rules. Additionally, our adoption of a PSA will be a significant change for APS customers, and we expect APS to educate and inform its customers about all aspects of that adjustor charge in a way that will minimize confusion and misunderstandings. We also expect APS to have the required information posted to its website and its customer education program up and running before June 1, 2005, in order to allow customers the opportunity to implement their own conservation measures. Finally, we want to make it clear to APS that our adoption of a PSA does not relieve it of its obligation to effectively and efficiently manage its fuel costs, and that we will closely monitor APS' performance.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

IV. FINDINGS OF FACT

1. APS is a public service corporation principally engaged in furnishing electricity in the State of Arizona. APS provides either retail or wholesale electric service to substantially all of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells and delivers electricity to wholesale customers in the western United States.

2. On June 27, 2003, APS filed with the Commission an application for a $175.1 million rate increase and for approval of a purchased power contract.

3. Notice of the application was provided in accordance with the law.

4. Intervention was granted to AECC, FEA, Kroger, RUCO, AUIA, Phelps Dodge, IBEW, ACA/DEAA, Panda, AWC, SWG, WRA, CNE, SEL, DVEP, UES, ACAA, Alliance, Wickenburg, AriSEIA, AARP, SWEEP, PPL Sundance, PPL Southwest, SWPG, Mesquite, and Bowie.

5. By Procedural Order issued August 15, 2003, the hearing was set to commence on April 7, 2004, and procedural dates were established for the filing of testimony and evidence.

6. On February 6, 2004, APS filed a Motion to Amend the Rate Case Procedural Schedule, and a procedural conference was held on February 18, 2004 to discuss the Motion.

7. By Amended Rate Case Procedural Order issued on February 20, 2004, the hearing date was rescheduled for May 25, 2004 and other procedural dates were modified.

8. On April 6, 2004, Staff filed a Motion to Amend the Procedural Schedule and on April 8, 2004, Staff filed a Memorandum indicating that representatives of APS had contacted Staff about the possibility of conducting settlement negotiations.

9. A public comment hearing was held on April 7, 2004.

10. On April 13, 2004, APS filed its Response to Staff's Motion and Staff Notice of Settlement Negotiations and requested a temporary suspension of the procedural schedule in order for settlement discussions to take place.

11. Pursuant to Procedural Orders issued April 7 and 12, 2004, a procedural conference to discuss Staff's Motion was held on April 15, 2004. By Procedural Order issued April 16, 2004, new

procedural dates were established and another procedural conference was scheduled for April 28, 2004.

12. The April 28, 2004 procedural conference was held as scheduled and by Procedural Order issued April 29, 2004, the procedural schedule was stayed and another procedural conference was scheduled for May 26, 2004.

13. Pursuant to procedural conferences held on May 26 and June 14, 2004, and Procedural Orders issued on May 26, June 18, and July 20, 2004, the stay was extended in order to allow the parties to discuss settlement.

14. At the August 18, 2004 Procedural Conference, the parties announced that they had reached a settlement, and the Settlement Agreement was docketed on that date.

15. On August 20, 2004, an Amended Rate Case Procedural Order was issued setting the hearing on the Settlement Agreement to commence on November 8, 2004.

16. The hearing was held as scheduled on November 8, 9, 10, 29, 30 and December 1, 2, and 3, 2004. Public comment was taken and testimony from the proponents of the Settlement Agreement was presented in panel format, and testimony from the ACA/DEAA was also presented in a panel format.

17. The Test Year ending 2002 Plant in Service was $4,876,901,000, excluding transmission plant, and including the PWEC assets as of December 31, 2004.

18. APS' FVRB is $5,054,426,000 and a 5.92 fair value rate of return is appropriate.

19. It is just and reasonable to authorize a total annual revenue increase in the amount of $75,500,000, consisting of an increase in base rates of approximately 3.77 percent or $67.6 million, and an increase in the CRCC surcharge of approximately .44 percent, which will collect $7.9 million.

20. A Power Supply Adjustor as set forth in the Settlement Agreement and as modified herein, is in the public interest.

21. APS is authorized to acquire the PWEC generation assets and rate base those assets at a value of $700 million as of December 31, 2004, under the terms and conditions as set forth in the Settlement Agreement and herein.

22. The Settlement Agreement will allow APS the opportunity to earn a reasonable rate of

return on its investment, will provide revenues sufficient for the Company to provide efficient and reliable service, and will allow for continued development of electric competition in Arizona.

23. APS shall implement a customer education program explaining how its PSA will work and shall maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs. APS shall submit its plan to implement its customer education program within 30 days of the effective date of this Decision to the Director of the Utilities Division for review and Staff shall keep the Commission apprised of the consumer education program. Furthermore, APS shall post the required information on its website within 30 days of the effective date of this Decision.

24. The parties to the Settlement Agreement shall submit a PSA Plan of Administration that reflects the determinations in this Decision for Commission approval within 60 days of the effective date of this Decision.

25. The depreciation rates and the costs for nuclear decommissioning as set forth in the Settlement Agreement are reasonable and appropriate.

26. Testimony was offered at the hearing that there was an inadvertent omission in Appendix J to the Settlement Agreement for Rate E-32-TOU in that the delivery-related demand charge for Rate E-032-TOU should have been reduced after the first 100 kW of demand for residual off-peak demand and that the initial rate block for residual off-peak delivery should be applied only to the first 100 kW of combined on-peak and residual off-peak demand. We will, therefore, direct APS to modify Rate E-32-TOU in accordance with these changes in its compliance filings.

27. We direct the parties to begin the DG workshop process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

28. In its study to be filed within 180 days of the effective date of this Decision concerning flexibility of on- and off-peak time periods and other time-of-use characteristics, APS shall also include a cost-benefit analysis of Surepay, APS' automatic payment program. The Company shall examine the cost effectiveness of the program and explore the possibility of offering a discount to those customers who participate in Surepay.

29. APS shall file additional time-of-use programs that are similar to the Time Advantage

and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

30. In a response (dated August 18, 2004) to a question from Commissioner Mundell regarding the break-over points for tiered rates, the parties to the Settlement Agreement indicated that rate E-12 has the most customers. The response also stated that the average use by a customer on rate E-12 is 770 kWh per month. Rate E-12 has three tiers with break-over points at 400 kWh per month and 800 kWh per month. Paragraph 57 of the Settlement Agreement requires APS to conduct a rate design study analyzing rate design modifications to promote energy efficiency, conservation, and reduce peak demand. As part of the study, we will require that one of the rate design modifications that APS shall investigate is to lower the first break-over point in rate E-12 to 350 kWh per month and lower the second break-over point to 750 kWh per month. In addition, the charge (rate) per kWh in the first tier (less than 350 kWh per month) should be lowered, while the rate for the third tier (over 750 kWh per month) should be raised. We will require that APS propose this type of rate design, or something very similar, for rate E-12 in its next rate case. We believe this type rate design, coupled with the DSM measures outlined in this Order, will encourage customers, especially high-use customers, to conserve energy (thereby lowering overall demand) and/or move to time-of-use rates (thereby lowering peak demand). If APS or any party to the next APS rate case believes this type rate design would be detrimental to APS and/or its customers, that party shall provide a detailed explanation and examples as to how and why this type rate design would be detrimental.

31. In order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

32. All DSM year-end reports filed at the Commission by APS must be certified by an Officer of the Company.

33. We are modifying the definition of "self-build" to include the acquisition of a generating unit or interest in a generating unit from any merchant or utility generator, and we will require APS to obtain the Commission's expressed approval for APS' acquisition of any generating facility or interest in a generating facility pursuant to a RFP or other competitive solicitation issued

before January 1, 2015. Our determination herein should not be construed as signaling in any manner the ultimate regulatory treatment that can or will be accorded to any generating facility or interest in a generating facility ultimately acquired by APS.

34. The workshops conducted by Staff on the development of needed infrastructure shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations. APS' aging coal fired plants face an increasingly emissions regulated future which may require sizeable investments to improve emissions control performance.

35. The Settlement Agreement also provides that renewable resources acquired through the special RFP or future solicitations shall be subject to the Commission's customary prudence review. And while the Settlement Agreement further stipulates that a renewable resource purchase shall not be found imprudent solely because the cost of the renewable resource exceeds market price, we stipulate conversely that a renewable resource purchase shall not be rendered prudent solely by virtue of the resource's cost being below 125 percent of market price.

36. In order to take advantage of any available federal tax credits for renewable energy production, APS should issue the 100 MW RFP no later than May 15, 2005.

37. If Arizona Public Service Company determines that it cannot meet the goal for renewable energy resources as set forth in Paragraph 69 of the Settlement Agreement, through in-state resources, it shall bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

38. We agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating. We are less inclined, however, to adopt an adjustor as a way to keep pace with load growth. Although APS' rebuttal testimony indicated that its fixed costs would increase in relation to its load growth, we are concerned about the potential for single-issue ratemaking and whether APS' fixed costs will increase in the same proportion as its fuel costs. According to the late-filed exhibits, the majority of the increased fuel costs are caused by increased load growth, rather than price volatility in fuel. In effect, the adjustor as designed provides annual step increases in rates. We believe APS must have an incentive to file a rate case so that we can

determine the accuracy of its assertion about expenses. Therefore, we will adopt an adjustor that collects or refunds the annual fuel costs that differ from the base year level. However, we will limit the adjustor to 4 mil from the base level over the entire term of the PSA and will cap the balancing account to an aggregate amount of $100 million. Should the Company seek to recover or refund a bank balance pursuant to Paragraph 19E of the Settlement Agreement, the timing and manner of recovery or refund of that existing bank balance will be addressed at such time. In no event shall the Company allow the bank balance to reach $100 million prior to seeking recovery or refund. Following a proceeding to recover or refund a bank balance between $50 million and $100 million, the bank balance shall be reset to zero unless otherwise ordered by the Commission.

39. Within three years of the effective date of this Decision, Staff shall commence a procurement review of APS' fuel, purchased power, generating practices and off-system sales practices.

40. Because we are concerned about the impact of the PSA on low-income customers, the PSA shall not apply to the bills of individuals who are enrolled in the Company's Energy Support program.

41. APS should work to make its low-income assistance programs widely available, including to Native Americans living inside the Company's service territory. Within six months of the effective date of this Order, APS shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance program. The plan should be filed with the Commission and made available to Tribal authorities within APS' service territory.

42. The Commission is also concerned that service reliability on rural Tribal lands has become degraded. Therefore, within six months of the effective date of this Order, APS should compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas. Moreover, APS shall participate in any future dockets related to enhancing reliability statewide.

V. CONCLUSIONS OF LAW

1. Arizona Public Service Company is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-222, 250, 251, and 376.

2. The Commission has jurisdiction over Arizona Public Service Company and the subject matter of the application.

3. Notice of the application was provided in accordance with the law.

4. The Settlement Agreement, with the modifications and additional provisions contained herein, resolves all matters raised by APS' rate application in a manner that is just and reasonable, and promotes the public interest.

5. The fair value of APS' rate base is $5,054,426,000, and 5.92 percent is a reasonable rate of return on APS' rate base.

6. The rates, charges, and conditions of service established herein are just and reasonable.

7. APS should be directed to file revised tariffs consistent with the Settlement Agreement and the findings contained in this Order.

VI. ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement attached hereto as Attachment A as modified herein is approved.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby directed to file with the Commission on or before March 31, 2005, revised schedules of rates and charges consistent with Exhibit A and the findings herein.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after April 1, 2005.

IT IS FURTHER ORDERED that Arizona Public Service Company shall notify its affected customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing and by posting on its website, in a form approved by the Commission's Utilities Division Staff.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement a customer education program explaining how its PSA will work and shall maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs.

IT IS FURTHER ORDERED that within 30 days of the effective date of this Decision, Arizona Public Service Company shall submit its plan to implement its customer education program to the Director of the Utilities Division for review and Staff shall keep the Commission apprised of the consumer education program.

IT IS FURTHER ORDERED that within 30 days of the effective date of this Decision, Arizona Public Service Company shall post on its website, information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement and comply with the terms of the Settlement Agreement including filing all reports, studies, and plans as set forth in the Settlement Agreement and as modified herein.

IT IS FURTHER ORDERED that the parties to the Settlement Agreement shall submit a PSA Plan of Administration that reflects the determinations in this Decision for Commission approval within 60 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company shall forgo any present or future claims of stranded costs associated with any of the PWEC assets.

IT IS FURTHER ORDERED that the Commission's Utilities Division Staff shall schedule workshops on resource planning issues and distributed generation issues within 90 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company shall modify Rate E-32-TOU in accordance with the discussion and findings herein.

IT IS FURTHER ORDERED that the parties shall begin the DG workshop process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

IT IS FURTHER ORDERED that in its study to be filed within 180 days of the effective date of this Decision concerning flexibility of on- and off-peak time periods and other time-of-use characteristics, Arizona Public Service Company shall also include a cost-benefit analysis of Surepay, Arizona Public Service Company's automatic payment program. The Company shall examine the cost effectiveness of the program and explore the possibility of offering a discount to those customers who participate in Surepay.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file additional time-of-use programs that are similar to the Time Advantage and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company's rate design study shall include the issues addressed in Findings of Fact No. 30, and Arizona Public Service Company shall propose a rate design addressing these issues in its next rate case.

IT IS FURTHER ORDERED that in order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

IT IS FURTHER ORDERED that all DSM year-end reports filed at the Commission by Arizona Public Service Company must be certified by an Officer of the Company.

IT IS FURTHER ORDERED that Arizona Public Service Company shall comply with Findings of Facts No. 33 when acquiring a generating unit or an interest in one.

IT IS FURTHER ORDERED that the resource planning workshops shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations.

IT IS FURTHER ORDERED that in order to take advantage of any available federal tax credits for renewable energy production, Arizona Public Service Company shall issue the 100 MW RFP no later than May 15, 2005.

IT IS FURTHER ORDERED that if Arizona Public Service Company determines that it cannot meet the goal for renewable energy resources as set forth in Paragraph 69 of the Settlement Agreement, through in-state resources, it shall bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

IT IS FURTHER ORDERED that within three years of the effective date of this Decision, Staff shall commence a procurement review of Arizona Public Service Company's fuel, purchased power, generating practices and off-system sales practices.

IT IS FURTHER ORDERED that the PSA shall not apply to the bills of individuals who are enrolled in the Company's Energy Support program.

IT IS FURTHER ORDERED that within six months of the effective date of this Decision, Arizona Public Service Company shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance programs. The plan shall be filed with the Commission and made available to Tribal authorities within Arizona Public Service Company's service territory.

IT IS FURTHER ORDERED that within six months of the effective date of this Decision, Arizona Public Service Company shall compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas, and Arizona Public Service Company shall participate in any future dockets related to enhancing reliability statewide.

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IT IS FURTHER ORDERED that the Commission's Utilities Division Staff shall initiate a rulemaking proceeding to modify A.A.C. R14-2-1618 within 120 days of the effective date of this Decision.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN | COMMISSIONER | COMMISSIONER

COMMISSIONER | COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 7th day of April, 2005.

BRIAN C. McNEIL
EXECUTIVE SECRETARY

DISSENT

DISSENT

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

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ATTACHMENT A

PROPOSED SETTLEMENT

OF

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY

REQUEST FOR RATE ADJUSTMENT

DECISION NO. 67744

PROPOSED SETTLEMENT
OF
DOCKET NO. E-01345A-03-0437
ARIZONA PUBLIC SERVICE COMPANY
REQUEST FOR RATE ADJUSTMENT

The purpose of this agreement ("Agreement") is to settle disputed issues related to Docket No. E-01345A-03-0437, Arizona Public Service Company's application to increase rates. This Agreement is entered into by the following entities:

Arizona Public Service Company ("APS")
Arizona Competitive Power Alliance
Federal Executive Agencies
Constellation NewEnergy, Inc.
Strategic Energy, L.L.C.
Southwest Energy Efficiency Project
Western Resource Advocates
Mesquite Power, L.L.C.
PPL Sundance Energy, L.L.C.
PPL Southwest Generation Holdings, L.L.C.
Arizonans for Electric Choice and Competition
Phelps Dodge Mining Company
Arizona Utility Investors Association
Southwestern Power Group II, LLC
Bowie Power Station
Arizona Community Action Association
IBEW, AFL-CIO, CLC, Local Unions 387, 640, and 769
Kroger Co.
Dome Valley Energy Partners, L.L.C.
Arizona Solar Energy Industries Association
Residential Utility Consumer Office
Staff, Arizona Corporation Commission

These entities shall be referred to collectively as "Parties." The following numbered paragraphs comprise the Parties' Agreement.

RECITALS

1. The purpose of this Agreement is to settle all issues presented by Docket No. E-01345A-03-0437 in a manner that will promote the public interest.

2. The Parties agree that the negotiation process undertaken in this matter was open to all Intervenors and provided all Intervenors with an equal opportunity to participate. All Intervenors were notified of the settlement process and encouraged to participate.

3. The Parties agree that the terms of this Agreement will serve the public interest by providing a just and reasonable resolution of the issues presented by APS' rate case, Docket No. E-01345A-03-0437. The adoption of this Agreement will further serve the public interest by allowing the Parties to avoid the expense and delay associated with litigation.

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TERMS AND CONDITIONS

I. Revenue Requirement

4. For ratemaking purposes and for the purposes of this Agreement, the Parties agree that APS will receive a total increase of $75,500,000 over its adjusted 2002 test year revenue of $1,791,584,000. This amount is equal to an approximate 3.77 percent increase in base rates plus an approximate .44 percent increase for the Competition Rules Compliance Charge discussed in Section XI of this Agreement. This equals a total increase of approximately 4.21 percent over APS' adjusted test year revenue.

5. For ratemaking purposes and for the purposes of this Agreement, the Parties agree that APS shall have a fair value rate base of $6,281,885,000. The revenue increase established in this Agreement will provide APS with an opportunity to earn a fair value rate of return of 5.92 percent.

II. PWEC Asset Treatment

6. In consideration of the provisions of this Agreement as a whole, the Parties agree that it is in the public interest for APS to acquire and to rate base the following units currently owned by Pinnacle West Energy Corporation ("PWEC"): West Phoenix CC-4, West Phoenix CC-5, Saguaro CT-3, Redhawk CC-1, and Redhawk CC-2 (collectively, the "PWEC Assets"). The generation costs related to these units will be recovered in the generation component of unbundled rates; the ancillary service costs related to these units will be recovered in the transmission component of unbundled rates.

7. The PWEC Assets shall have an original cost rate base value of $700 million, which represents a $148,000,000 disallowance from the original cost of these assets as of December 31, 2004. This disallowance represents a reasonable estimate of the value to APS' ratepayers of the remaining term of the Track B contract between APS and PWEC.

8. APS will forego any present or future claims of stranded costs associated with any of the PWEC Assets.

9. The Parties recognize that APS is required to seek approval of certain aspects of the asset transfer from the Federal Energy Regulatory Commission ("FERC"). APS will use its best efforts to obtain such approval. APS shall file a request for FERC approval of the asset transfer no sooner than the date of the Commission's approval of this matter but no later than thirty days after such approval. If the Commission approves the Agreement without material change, APS shall be authorized to inform FERC that the Parties support APS' efforts to obtain FERC approval of the specific asset transfer set forth in this Agreement. If the Commission approves the Agreement with one or more material changes, APS shall not claim the support of any Party that is adversely affected by the material change(s) without first obtaining that Party's consent. No Party shall file with FERC any objection to the asset transfer, and no Party shall be

obligated to intervene or to join or file any pleadings in support of FERC approval of the asset transfer.

10. To bridge the time between the effective date of the rate increase and the actual date of the asset transfer, APS and PWEC will execute a cost-based purchased power agreement ("Bridge PPA"), which will be based on the value of the PWEC Assets established in Paragraph 7. During the term of the Bridge PPA, APS will flow fuel costs related to the PWEC Assets and off-system sales revenue related to the PWEC Assets through the power supply adjustor ("PSA") addressed in Section IV below. Any demand and non-fuel energy charges incurred under this Bridge PPA will be excluded from recovery under the PSA because they are already included in APS' base rates.

11. The Bridge PPA shall remain in effect until FERC issues a final order approving the transfer of the PWEC assets to APS and such transfer is completed. For purposes of this paragraph, a "final order" is an order that is no longer subject to appeal.

12. If FERC issues an order denying APS' request to acquire the PWEC Assets, the Bridge PPA will become a thirty-year PPA. Prices in this thirty-year PPA will reflect cost-of-service as determined by the Commission in APS' rate proceedings as if APS had acquired and rate-based the PWEC Assets at the value established in Paragraph 7. During the term of the thirty-year PPA, APS will flow fuel costs related to the PWEC Assets and off-system sales revenue related to the PWEC Assets through the PSA addressed in Section IV below. Unless otherwise ordered by the Commission, any demand and non-fuel energy charges incurred under this long-term PPA will be excluded from recovery under the PSA and will instead be reflected in APS' base rates. Except as specifically set forth in this Paragraph, this Agreement does not establish the regulatory or ratemaking treatment of the long-term PPA.

13. If FERC issues an order approving APS' request to acquire the PWEC Assets at a value materially less than $700 million, or if FERC issues an order approving the transfer of fewer than all of the PWEC Assets, or if FERC issues an order that is materially inconsistent with this Agreement, APS shall promptly file an appropriate application with the Commission so that rates may be adjusted. In these circumstances, the Bridge PPA shall continue at least until the conclusion of this subsequent proceeding to consider any appropriate adjustment to APS' rates.

14. The basis point credit established in Decision No. 65796 will continue as long as the associated debt between APS and PWEC is outstanding. Credit for amounts deferred after December 31, 2004 shall be reflected in APS' next general rate proceeding.

15. The Parties agree that West Phoenix CC-4 and West Phoenix CC-5 shall be deemed to be "local generation" as that term is defined in the AISA protocol or any successor FERC-approved protocol. During must-run conditions, generation from the West Phoenix facility shall be available at FERC-approved cost-of-service prices to electric service providers serving direct access load in the Phoenix load pocket.

III. Cost of Capital

16. The Parties agree that a capital structure of 55% long-term debt and 45% common equity shall be adopted for ratemaking purposes.

17. The Parties agree that a return on common equity of 10.25% is appropriate.

18. The Parties agree that an embedded cost of long-term debt of 5.8% is appropriate.

IV. Power Supply Adjustor

19. A Power Supply Adjustor ("PSA") shall be adopted with the following characteristics.

a. The PSA shall include both fuel and purchased power.

b. The adjustor rate, initially set at zero, will be reset on April 1, 2006 and thereafter on April 1st of each subsequent year. APS will submit a publicly available report that shows the calculation of the new rate on March 1, 2006 and thereafter on March 1st of each subsequent year. The adjustor rate shall become effective with the first billing cycle in April unless suspended by the Commission.

c. There shall be an incentive mechanism where APS and its customers shall share in the costs or savings. The percentage of sharing shall be ninety (90) percent for the customers and ten (10) percent for APS with no maximum sharing amount.

d. There shall be a bandwidth which shall limit the change in the adjustor rate to plus or minus $0.004 per kilowatt hour ("kWh") per year. Any additional recoverable or refundable amounts shall be recorded in a balancing account and shall carry over to the subsequent year or years. The carryover amount shall not be subject to further sharing as described above in Paragraph 19.c in the subsequent year or years.

e. When the size of the balancing account reaches either plus or minus $50 million, APS will have forty-five days to file for Commission approval of a surcharge to amortize the over-recovered/under-recovered balance and to reset the balancing account to zero. If APS does not want to reset the balance to zero, it shall file a report explaining why. Commission action shall be required to establish or revise a surcharge created pursuant to this provision.

f. Subject to paragraphs 19.c and 19.d, ratepayers shall receive the benefits of all off-system sales margins through a credit to the PSA balance.

g. The PSA is the appropriate mechanism for recovery of the prudent direct costs of contracts used for hedging fuel and purchased power costs.

h. The balancing account shall accrue interest based on the one-year nominal Treasury constant maturities rate. This rate is contained in the Federal Reserve Statistical Release, H-15, or its successor publication.

i. The Commission or its Staff may review the prudence of fuel and power purchases at any time.

j. The Commission or its Staff may review any calculations associated with the PSA at any time.

k. Any costs flowed through the adjustor shall be subject to refund if the Commission later determines that the costs were not prudently incurred.

20. Beginning sixty days from the effective date of a Commission order approving this Agreement, APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. These monthly reports shall thereafter be due on the first day of the third month following the end of the reporting month. These reports shall be publicly available and shall contain, at a minimum, the following items:

a. Bank balance calculation, including all inputs and outputs.

b. Total power and fuel costs.

c Customer sales in both kWh and dollars by customer class.

d. The number of customers by customer class.

e. A detailed listing of all items excluded from the PSA calculations.

f. A detailed listing of any adjustments to adjustor reports.

g. Total off-system sales margins.

h. System losses in MW and MWh.

i. Monthly maximum retail demand in MW.

j. Identification of a contact person and phone number from APS for questions.

21. Beginning sixty days from the effective date of a Commission order approving this Agreement, APS shall provide additional reports to Staff each month including information as set forth in paragraphs 22, 23, and 24 about APS' generating units, power purchases, and fuel purchases. These monthly reports shall thereafter be due on the first day of the third month

following the end of the reporting month. These additional reports may be provided confidentially.

22. The information for each generating unit shall include, at a minimum, the following items:

a. The net generation, in MWh per month, and twelve months cumulatively.

b. The average heat rate, both monthly and twelve-month average.

c. The equivalent forced-outage rate, both monthly and twelve-month average.

d. The outage information for each month, including, but not limited to event type, start date and time, end date and time, description.

e. Total fuel costs per month.

f. The fuel cost per kWh per month.

23. At a minimum, the information on power purchases shall consist of the following items per seller:

a. The quantity purchased in MWh.

b. The demand purchased in MW to the extent specified in contract.

c. The total cost for demand to the extent specified in contract.

d. The total cost for energy.

Information on economy interchange purchases may be aggregated. These reports shall also include an itemization of off-system sales margins.

24. At a minimum, the information on fuel purchases shall consist of the following information:

a. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge and incremental cost.

b. Natural gas commodity costs, categorized by short term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume, by contract.

25. Within sixty days after Commission approval of this Agreement, APS shall provide the information specified in paragraphs 20-24 relating to the base cost of fuel and purchased power adopted for the test year settlement revenue requirement.

26. An APS Officer shall certify under oath that all information provided in the reports required under Paragraphs 20 through 25 is true and accurate to the best of his or her information and belief.

27. Direct access customers and customers served under Rates E-36, SP-1, Solar-1, and Solar-2 shall be excluded from paying charges under the PSA.

28. The minimum life of the PSA shall be five years measured from the date that rates resulting from this proceeding go into effect. No later than four years from the date of the PSA's implementation, APS shall file a report that addresses the PSA's operation, its merits, and its shortcomings and that provides recommendations, with supporting testimony, as to whether the PSA should remain in effect. The Commission shall consider whether to continue the PSA after APS has filed its PSA report or during APS' next rate case, whichever comes first. If the PSA is reviewed during an APS rate case that concludes before the expiration of the five-year period, or if the Commission's review of APS' PSA report concludes before the expiration of the five-year period, any recommendations to abolish the PSA shall not take effect until the five-year period has expired.

29. If the Commission decides to retain the PSA after the review described in paragraph 28, the Commission may nonetheless, in conformance with applicable procedural requirements, abolish the PSA at any time after the five-year period has expired and need not conduct a rate case to do so.

30. If the Commission abolishes the PSA, the Commission shall make appropriate provision for any under-recovery or over-recovery that exists at the time of termination. The Commission may also adjust APS' base rates as appropriate to ensure that they reflect the costs for fuel and purchased power.

31. The Parties agree to a base cost of fuel and purchased power of $0.020743 per kWh. This amount shall be reflected in APS' base rates.

32. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the PSA shall operate.

V. Depreciation

33. APS has agreed to adopt Staff's proposed service lives as set forth in Staff's direct testimony, including the service lives proposed by Staff for the PWEC Assets. The Parties further agree that APS shall be allowed a jurisdictional net salvage allowance as reflected in APS' direct testimony.

34. The attached Appendix A sets forth the remaining service lives, net salvage allowance, annual depreciation rates, and reserve allocation for each category of APS depreciable property agreed to by the Parties for purposes of this proceeding and authorized by the Commission's approval of this Agreement.

35. APS will separately record and account for net salvage such that it can be identified both as a component to annual depreciation expense and in accumulated reserves for depreciation.

36. Amortization rates currently in effect, which are shown in Appendix A, are to remain in effect.

37. For the purposes of this proceeding, the Parties agree that SFAS 143 shall not be adopted for ratemaking purposes.

VI. $234 Million Write-Off

38. APS shall not recover the $234 million write-off attributable to Decision No. 61973, the Commission order that approved the 1999 APS Settlement Agreement.

39. APS shall not seek to recover the above $234 million write-off in any subsequent proceeding.

VII. Demand Side Management ("DSM")

40. Included in APS' total test year settlement base rate revenue requirement is an annual $10 million base rate DSM allowance for the costs of approved "eligible DSM-related items," as defined in this paragraph. In addition to expending the annual $10 million base rate allowance, APS will be obligated to spend on average at least another $6 million annually on approved eligible DSM-related items, such additional amounts to be recovered by means of a DSM adjustment mechanism as described in paragraph 43 herein. Accordingly, APS will be obligated under this Settlement Agreement to spend at least $48 million ($30 million in base rates and at least another $18 million during calendar years 2005 – 2007, with the latter amount to be recovered by the aforementioned DSM adjustment mechanism) on approved eligible DSM-related items, all as provided in this Section VII. For purposes of this Agreement, "eligible DSM-related items" shall include and be limited to "energy-efficiency DSM programs", as also defined in this paragraph; a "performance incentive" in accordance with paragraph 45; and "low income bill assistance" as specified in paragraph 42. For purposes of this Agreement, "energy-efficiency DSM" shall be defined as the planning, implementation and evaluation of programs that reduce the use of electricity by means of energy-efficiency products, services, or practices.

41. All DSM programs must be pre-approved before APS may include their costs in any determination of total DSM costs incurred. APS may apply the costs of programs already approved by Staff or the Commission prior to the effective date of Commission approval of this Agreement to the annual $10 million base rate DSM allowance and to the additional spending on eligible DSM-related items provided for in paragraphs 40 and 44. After the Commission issues an order approving the terms of this Agreement, APS shall submit proposed DSM programs to the Commission for approval.

42. The annual $10 million base rate DSM allowance referenced above shall include at least $1 million annually for the low income weatherization program. Up to $250,000 of the $1 million provided for the low income weatherization program may be applied to low income bill assistance during any calendar year. If APS does not expend the entire $250,000 on low income bill assistance, the balance shall be available for low income weatherization. APS shall file an application for Commission approval of the low income weatherization program, including bill assistance and administrative costs, within sixty days of the Commission's approval of this Agreement.

43. A DSM adjustment mechanism will be established in this proceeding for any approved DSM expenditures in excess of the annual $10 million base rate DSM allowance. The adjustor rate, initially set at zero, will be reset on March 1, 2006 and thereafter on March 1st of each subsequent year. Before March 1st, beginning in 2006, APS shall file a request with supporting documentation to revise its DSM adjustor rate. The per-kWh charge for the year will be calculated by dividing the account balance by the number of kWh used by customers in the previous calendar year. General Service customers that are demand billed will pay a per kW charge instead of a per kWh charge. To calculate the per kW charge, the account balance shall first be allocated to the General Service class based upon the number of kWh consumed by that class. General Service customers that are not demand billed shall pay the DSM adjustor rate on a per kWh basis. The remainder of the account balance allocated to the General Service class shall then be divided by the kW billing determinant for the demand billed customers in that class to determine the per kW DSM adjustor charge. The DSM adjustor will be applied to both standard offer and direct access customers.

44. As provided for in paragraph 40, and in addition to the annual $10 million base rate DSM allowance, APS will spend on average at least $6 million annually on approved eligible DSM-related items to be recovered by the DSM adjustor mechanism established in paragraph 43. APS may gradually phase-in its DSM spending, but will be obligated to expend no less than $48 million, $30 million in base rates and at least $18 million to be recovered through the DSM adjustment mechanism established under paragraph 43, all on approved and eligible DSM-related items over the initial three-year period of calendar years 2005 through 2007. Moreover, APS will be obligated to expend at least $13 million on approved and eligible DSM-related items during 2005 (subject to the Commission's timely approval of sufficient programs), with such $13 million spending obligation to be pro-rated for 2005 to the extent Commission approval of the Final Plan called for in paragraph 48 occurs after January 1, 2005. In no event will such pro-ration reduce APS' 2005 obligation below the annual $10 million base rate DSM allowance. Consistent with paragraph 43, all required and approved spending on eligible DSM-related items above the annual $10 million base rate allowance will be recovered by APS only on an "after-the-fact" basis through the DSM adjustment mechanism.

45. APS will be permitted to earn and recover a performance incentive based on a share of the net economic benefits (benefits minus costs) from the energy-efficiency DSM programs approved in accordance with paragraph 41. Such performance incentive will be capped at 10% of the total amount of DSM spending, inclusive of the program incentive, provided for in this Agreement (e.g., $1.6 million out of the $16 million average annual spending referenced in paragraphs 40 and 44 or $4.8 million over the initial three-year period). Any such performance

incentive collected by APS during a test year will be considered as a credit against APS' test year base revenue requirement. The specific performance incentive will be set forth in and approved as a part of the Final Plan referenced in paragraph 48.

46. This Agreement does not provide for the recovery of net lost revenues. Except to the extent reflected in a test year used to establish APS rates in future rate proceedings, or unless otherwise authorized by the Commission in a separate non-rate case proceeding, APS shall not recover or seek to recover net lost revenues on a going-forward basis. In no event will APS recover or seek to recover net lost revenues incurred in periods prior to such test year or for periods prior to the Commission's authorization of net lost revenue recovery in a separate non-rate case proceeding. In addition, no recovery of net lost revenues by APS will reduce the DSM spending commitments embodied in this Agreement or be considered as an eligible DSM-related item for purposes of this Section.

47. Attached as Appendix B is a preliminary plan ("Preliminary Plan") for eligible DSM-related items for calendar 2005, including a listing and brief description of programs, program concepts and program strategies and tactics. The Preliminary Plan also provides a preliminary allocation of the $16 million referenced in paragraph 40. The Preliminary Plan will be considered and approved by the Commission as part of this Agreement.

48. Within 120 days of the Commission's approval of the Preliminary Plan, APS will, with input and assistance from the collaborative created pursuant to paragraph 54, file with the Commission a final 2005 DSM plan ("Final Plan") that is consistent with the approved Preliminary Plan. The Final Plan will be submitted to the Commission for its consideration and approval. As part of the Commission's review, Staff shall report its recommendation to the Commission regarding the Final Plan, including its recommendations regarding the program budgets, estimates of energy savings and load reductions, and the cost-effectiveness of such Final Plan.

49. APS may request Commission approval for DSM program costs and performance incentives that exceed the $16 million ($48 million over three years) level referenced in paragraph 40. Such additional DSM programs may include demand-side response and additional energy efficiency programs.

50. For residential billing purposes, APS shall combine the DSM adjustor with the EPS adjustor addressed in paragraph 63 and shall reflect such combined billing charge as an "Environmental Benefits Surcharge." For the billing of general service and other non-residential customers, APS may but is not required to provide for such combined billing of the EPS and DSM adjustment mechanisms. In any event, each such adjustor shall be separately set forth in the Company's rate schedules and shall be separately accounted for in the Company's books, records, and reports to the Commission.

51. If, notwithstanding the provisions of paragraphs 40 and 44, APS does not expend during calendar years 2005 through 2007 at least $30 million (in total) of the base rate allowance referenced in paragraph 40 for approved and eligible DSM-related items, as that latter term is defined in paragraph 40, the unspent amount of the $30 million will be credited to the account balance for the DSM adjustor described in Paragraph 43 in 2008.

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52. Beginning in 2005, APS will file mid-year and end-year reports in Docket Control containing the following information separately for each DSM program:

a. A brief description of the program.

b. Program modifications.

c. Program goals, objectives, and savings targets.

d. Programs terminated.

e. The level of participation.

f. A description of evaluation and monitoring activities and results.

g. kW and kWh savings.

h. Benefits and net benefits, both in dollars, as well as performance incentive calculation.

i. Problems encountered and proposed solutions.

j. Costs incurred during the reporting period disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs.

k. Findings from all research projects.

l. Other significant information.

Each report will be due on the first day of the third month after the conclusion of the reporting period.

53. Direct access customers shall be eligible to participate in APS DSM programs.

54. APS shall implement and maintain a collaborative DSM working group to solicit and facilitate stakeholder input, advise APS on program implementation, develop future DSM programs, and review DSM program performance. The DSM working group shall review APS' draft program plans and reports before APS submits them to the Commission. APS shall, however, retain responsibility for demonstrating to the Commission the appropriateness of any program proposed by APS. Any DSM program proposed by APS may be modified by the Commission as it finds appropriate. If APS does not submit a DSM program proposal considered by the collaborative DSM working group to the Commission, any member of the working group may submit the proposal directly to the Commission for its review and approval with such modifications as the Commission finds appropriate. In such instance, the member or members submitting a proposal shall have the responsibility for demonstrating the appropriateness of that

program to the Commission. At a minimum, Staff, RUCO, AECC, the Arizona State Energy Office, WRA and SWEEP will be invited to participate with APS in the above collaborative DSM working group. Commission Staff shall continue to exercise its responsibility to review and make independent recommendations to the Commission in connection with any DSM program proposal submitted by APS or any other member of the working group.

55. APS shall conduct a study to review and evaluate the merits of allowing large customers to self-direct any DSM investments. In conducting this study, APS shall seek the input of the collaborative DSM working group provided by paragraph 54. This study shall be filed within one year of the Commission's approval of this Agreement.

56. Any customer who can demonstrate an active DSM program and whose single site usage is twenty MW or greater may file a petition with the Commission for exemption from the DSM adjustor. The public shall have 20 days to comment on such petition. In considering any petition pursuant to this paragraph, the Commission may consider the comments received and any other information that is relevant to the customer's request.

57. Rate designs that encourage energy efficiency, discourage wasteful and uneconomic use of energy, and reduce peak demand are integral parts of an overall DSM strategy. To that end, APS will conduct a study analyzing rate design modifications that could include, among others, consideration of mandatory TOU rates (e.g., for E-32 general service customers) and/or expanded use of inclining block rates. A plan for such study and analysis of rate design modifications shall be presented to the collaborative DSM working group described in paragraph 54 within 90 days of the Commission's approval of this Agreement. APS will submit to the Commission the final results of this study and analysis of rate design modifications as part of its next general rate application or within 15 months of approval of this Agreement, whichever occurs first. If the study and analysis indicate that one or more of the rate design modifications studied is reasonable, cost-effective and practical, APS shall develop and propose to the Commission any appropriate rate design modifications.

58. The DSM activities provided for in this section are in addition to any DSM acquired as part of the competitive procurement process described in Section IX.

59. The Commission will address other issues, such as DSM goals, cost-effectiveness, and evaluation, in a generic proceeding.

60. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the DSM adjustor shall operate. Commission Staff shall review and approve the plan of administration in connection with its overall compliance review following APS' compliance filings in this docket.

VIII. Environmental Portfolio Standard and other Renewables Programs

61. Included in APS' total test year settlement revenue requirement and existing EPS surcharge revenues is $12.5 million for renewables as defined in the Commission's environmental portfolio standard ("EPS"), A.A.C. R14-2-1618 ("Rule 1618").

62. APS shall recover $6 million of the above $12.5 million in the base rates provided for in this Agreement.

63. APS shall also recover costs for EPS-eligible renewables through the EPS surcharge, which shall be established in this case as an adjustment mechanism to allow for specific Commission-approved changes to APS' EPS funding. The initial charge will be the same as contained in the current EPS surcharge tariff, including caps. If the Commission amends the EPS surcharge set forth in Rule 1618 or approves additional EPS funding pursuant to paragraph 64 of this Agreement, any change in EPS funding requirements resulting from such actions shall be collected from APS' customers in a manner that maintains the proportions between customer categories embodied in the current EPS surcharge. These adjustments may be made outside a rate case.

64. Prior to spending additional funds, APS may apply to the Commission to increase its EPS funding beyond that provided in base rates and the EPS surcharge. In its application, APS shall provide the following information:

a. APS shall explain why it has been unable to meet the standard.

b. APS shall account for all EPS funds that it has collected from ratepayers and shall describe how they were spent.

c. APS shall support the prudence and cost effectiveness of all its EPS expenditures.

d. APS shall demonstrate that it has appropriately managed its EPS funding and programs.

e. If APS has chosen to expend EPS funding on technologies, programs, or other items that do not represent the least cost method for meeting the standard established in Rule 1618, APS shall identify each such instance and explain why it chose to employ other than the least cost alternative.

f. APS shall set forth a plan for meeting the standard and shall support the cost effectiveness of each element of the plan. Where the plan does not employ the least cost alternative, APS shall identify each such instance and shall explain why it is reasonable to elect a more expensive alternative.

g. APS shall provide the proposed budget that it believes would allow it to meet the standard and shall explain the cost effectiveness of every item addressed in the budget.

h. In its application, APS shall address whether ratepayers would benefit from partial or phased implementation of the plan and associated budget provided in response to paragraphs 64.f and 64.g.

i. APS shall identify any potential impacts on ratepayers of additional EPS funding and shall consider how any adverse impacts may be mitigated.

The Commission, in its discretion, may deny APS' application for additional EPS funding. APS may not file an application pursuant to this paragraph until one year after the termination of the rulemaking docket resulting from paragraph 68.

65. The EPS surcharge shall be recovered from both standard offer and direct access customers. APS shall separately account for EPS revenue collected from direct access customers, and such revenue shall be available to electric service providers for funding their EPS obligations.

66. For billing purposes, APS may combine the EPS adjustor with the DSM adjustor as addressed in paragraph 50.

67. After the Commission issues an order approving the terms of this Agreement, renewables programs directly involving APS' retail customers will be submitted to the Commission for approval.

68. The Commission will address issues such as modifying EPS goals or requirements in a generic proceeding. Staff will initiate a rulemaking proceeding to modify Rule 1618 within 120 days of the Commission's approval of this Agreement.

69. APS will issue a special RFP in 2005 seeking at least 100 MW and at least 250,000 MWh per year of any of the following types of renewable energy resources for delivery beginning in 2006: solar, biomass/biogas, wind, small hydro (under 10 MW), hydrogen (other than from natural gas), or geothermal. APS will, either in this solicitation or in subsequent procurements for renewables, seek to acquire at least ten percent of its annual incremental peak capacity needs from renewable resources. The renewable resources solicited by this RFP or future solicitations issued pursuant to this paragraph shall be subject to the following conditions:

a. Resources need not provide firm capacity, but APS will take into consideration the degree of the resource's firmness in determining the appropriate capacity value to assign to such resource.

b. Individual resources must be capable of providing at least 20,000 MWh of renewable energy annually.

c. Resources must be deliverable to the APS system, either directly or through displacement (tradable tags or credits alone will not suffice), and the costs of integrating a specified resource into the APS system will be considered in determining whether a proposed resource meets the pricing requirements of this paragraph.

d. Resources may be, but need not be, EPS-eligible.

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e. Purchased power agreements ("PPAs") offering renewable energy must be for a minimum term of five years, but may be for terms, including renewal options, of as long as thirty years.

f. Respondents to this renewable energy RFP must offer products with either fixed prices or relatively stable prices that do not vary with either the price of natural gas or of electricity.

g. Renewable resources must be no more costly, on a levelized cost per MWh basis, than 125% of the reasonably estimated market price of conventional resource alternatives.

h. If APS purchases renewable resources through a PPA, the portion of the cost of those resources that is at or below market price may be recovered through the PSA similar to other PPA costs.

i. If APS purchases through a PPA renewable resources that are not eligible for EPS recovery, the portion of the cost of those resources that is above market price may be recovered through the PSA similar to other PPA costs.

j. If APS purchases through a PPA renewable resources that are eligible to meet EPS requirements, the portion of the cost of those resources that is above market price will be recovered from EPS funds; however, such recovery of cost premiums from EPS funds in any year shall be limited to the kWh, expanded by any applicable multipliers, necessary to meet then-existing EPS requirements for that year. If the portion of the cost that is above market price exceeds the amount that is available from the EPS funds as indicated above, or if the EPS funding is exhausted, the remainder may be recovered through the PSA.

k. The net proceeds from the sale of any environmental credits or tags attributable to the renewable resources acquired pursuant to this paragraph shall be credited to the EPS account.

l. Where feasible, utilization of in-state renewable resources is desirable, subject to the limitations and requirements set forth above, but if APS does not receive sufficient in-state qualified bids, APS is free to acquire qualifying out-of-state resources to meet its initial goal of at least 100 MW or its subsequent goal of acquiring at least ten percent of its incremental capacity needs from renewable resources.

m. Renewable resources acquired through this RFP or pursuant to Section IX that otherwise qualify for EPS treatment will be considered as applying to any EPS standard.

n. Renewable resources acquired through this RFP, through future solicitations for renewables, or pursuant to Section IX shall be subject to the Commission's customary prudence review. The fact that the cost of resources acquired pursuant to this paragraph exceeds market price shall not, in and of itself, render such purchases imprudent.

70. At least thirty days before APS issues the final RFP for renewable resources pursuant to this section, APS will circulate a draft of the RFP to potentially interested parties. At least ten days before APS issues the final RFP, APS will conduct an informal meeting with potential bidders and other interested parties to allow an opportunity for comments and discussion regarding the RFP.

71. If, by December 31, 2006, APS has failed to acquire at least 100 MW of renewable resources pursuant to the RFP described in paragraph 69, APS shall, no later than January 31, 2007, file a notice with the Commission describing the shortfall in renewable resources, explaining the circumstances leading to the shortfall, and recommending actions to the Commission. This notice shall be sent to all Parties of record in this case. Any interested person may request that the Commission conduct a proceeding.

72. The provisions of this section shall not displace APS' requirements under the EPS or any modifications to the EPS.

73. APS will allow and encourage all renewable resources (whether or not EPS-eligible), distributed generation, and DSM proposals to participate in the 2005 RFP or similar competitive solicitation discussed in Section IX.

IX. Competitive Procurement of Power

74. APS will not pursue any self-build option having an in-service date prior to January 1, 2015, unless expressly authorized by the Commission. For purposes of this Agreement, "self-build" does not include the acquisition of a generating unit or interest in a generating unit from a non-affiliated merchant or utility generator, the acquisition of temporary generation needed for system reliability, distributed generation of less than fifty MW per location, renewable resources, or the up-rating of APS generation, which up-rating shall not include the installation of new units.

75. As part of any APS request for Commission authorization to self-build generation prior to 2015, APS will address:

a. The Company's specific unmet needs for additional long-term resources.

b. The Company's efforts to secure adequate and reasonably-priced long-term resources from the competitive wholesale market to meet these needs.

c. The reasons why APS believes those efforts have been unsuccessful, either in whole or in part.

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d. The extent to which the request to self-build generation is consistent with any applicable Company resource plans and competitive resource acquisition rules or orders resulting from the workshop/rulemaking proceeding described in paragraph 79.

e. The anticipated life-cycle cost of the proposed self-build option in comparison with suitable alternatives available from the competitive market for a comparable period of time.

76. Nothing in this section shall be construed as relieving APS of its existing obligation to prudently acquire generating resources, including but not limited to seeking the above authorization to self-build a generating resource or resources prior to 2015.

77. The issuance of any RFP or the conduct of any other competitive solicitation in the future shall not, in and of itself, preclude APS from negotiating bilateral agreements with non-affiliated parties.

78. Notwithstanding its ability to pursue bilateral agreements with non-affiliates for long-term resources, APS will issue an RFP or other competitive solicitation(s) no later than the end of 2005 seeking long-term future resources of not less than 1000 MW for 2007 and beyond.

a. For purposes of this section, "long-term" resources means any acquisition of a generating facility or an interest in a generating facility, or any PPA having a term, including any extensions exercisable by APS on a unilateral basis, of five years or longer.

b. Neither PWEC nor any other APS affiliate will participate in such RFP or other competitive solicitation(s) for long-term resources, and neither PWEC nor any other APS affiliate will participate in future APS competitive solicitations for long-terms resources without the appointment by the Commission or its Staff of an independent monitor.

c. Nothing in this section shall be construed as obligating APS to accept any specific bid or combination of bids.

d. All renewable resources, distributed generation, and DSM will be invited to compete in such RFP or other competitive solicitation and will be evaluated in a consistent manner with all other bids, including their life-cycle costs compared to alternatives of comparable duration and quality.

79. The Commission Staff will schedule workshops on resource planning issues to focus on developing needed infrastructure and developing a flexible, timely, and fair competitive procurement process. These workshops will also consider whether and to what extent the competitive procurement should include an appropriate consideration of a diverse portfolio of short, medium, and long-term purchased power, utility-owned generation, renewables, DSM, and

distributed generation. The workshops will be open to all stakeholders and to the public. If necessary, the workshops may be followed with rulemaking.

80. APS will continue to use its Secondary Procurement Protocol except as modified by the express terms of this Agreement or unless the Commission authorizes otherwise.

X. Regulatory Issues

81. The Parties acknowledge that APS has the obligation to plan for and serve all customers in its certificated service area, irrespective of size, and to recognize, in its planning, the existence of any Commission direct access program and the potential for future direct access customers. This section does not bar any Party from seeking to amend APS' obligation to serve.

82. Changes in retail access shall be addressed through the Electric Competition Advisory Group ("ECAG") or other similar process. The ECAG process or similar proceeding shall address, among other things, the resale by Affected Utilities of Revenue Cycle Services ("RCSs") to Electric Service Providers ("ESPs").

83. The Parties further acknowledge that APS currently has the ability, subject to applicable regulatory requirements, to self-build or buy new generation assets for native load, subject to paragraph 81, and subject to the conditions in Section IX of this Agreement.

84. The Parties acknowledge that APS may join a FERC-approved Regional Transmission Organization ("RTO") or an entity or entities performing the functions of an RTO. APS may participate in those activities or similar activities without further order or authorization from the Commission. This paragraph does not establish the ratemaking treatment for costs related to those activities.

85. This section is not intended to create or confirm an exclusive right for APS to provide electric service within its certificated area where others may legally also provide such service, to diminish any of APS' rights to serve customers within its certificated area, or to prevent the Commission or any other governmental entity from amending the laws and regulations relative to public service corporations.

XI. Competition Rules Compliance Charge ("CRCC")

86. Included in the total test year revenue requirement is approximately $8 million for the CRCC. APS may recover $47.7 million plus interest calculated in accordance with paragraph 19.h through a CRCC of $0.000338/kWh over a collection period of five years.

87. When the above amount is recovered, the CRCC will terminate immediately. If any amount remains unrecovered/overrecovered after the end of the five year period, APS shall file an application with the Commission to adjust the CRCC to recover/refund the balance.

88. The CRCC shall be a separate surcharge, i.e., it shall not be included in base rates. The CRCC shall be assessed against all customers except for those served on rate schedules Solar-1 or Solar-2.

89. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the CRCC shall operate.

XII. Low Income Programs

90. APS shall increase funding for marketing its E-3 and E-4 tariffs to a total of $150,000.

91. APS shall increase its E-3 tariff discount levels as follows in Table 1 below:

Table 1 – E-3 Discount Levels		
Usage Level	**Current Discount**	**New Discount**
0-400 kWh	30 %	40 %
401-800 kWh	20 %	26 %
801-1200 kWh	10 %	14 %
Over 1200 kWh	$10.00	$13.00

92. APS shall increase its E-4 tariff discount levels as follows in Table 2 below:

Table 2 – E-4 Discount Levels		
Usage Level	**Current Discount**	**New Discount**
0-800 kWh	30 %	40 %
801-1400 kWh	20 %	26 %
1401-2000 kWh	10 %	14 %
Over 2000 kWh	$20.00	$26.00

93. It is the Parties' intent to insulate eligible low income customers from the effects of the rate increase resulting from this Agreement. With the revisions to the E-3 and E-4 tariff discounts set forth above, eligible low income customers will receive a net reduction in rates.

XIII. Returning Customer Direct Access Charge

94. The Returning Customer Direct Access Charge ("RCDAC") shall be established, subject to the following conditions approved in Decision No. 66567:

a. The charge shall apply only to individual customers or aggregated groups of customers of 3 MW or greater.

b. The charge shall not apply to a customer who provides APS with one year's advance notice of intent to take Standard Offer service.

c. The RCDAC rate schedule shall include a breakdown of the individual components of the potential charge, definitions of the components, and a general framework that describes the way in which the RCDAC would be calculated.

95. The RCDAC shall only be established to recover from Direct Access customers the additional costs, both one-time and recurring, that these customers would otherwise impose on other Standard Offer customers if and when the former return to standard offer service from their competitive suppliers. The RCDAC shall not last longer than twelve months for any individual customer.

96. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the RCDAC shall operate.

XIV. Service Schedule Changes

97. The Company's proposed Schedule 1 changes shall be adopted as modified by Staff. Attached as Appendix C is Schedule 1 with the modifications provided for by this Agreement.

98. The Company's changes to Schedule 3 proposed in its direct testimony shall be adopted but with the retention of the 1,000-foot construction allowance for individual residential customers and also with any individual residential advances of costs being refundable. Attached as Appendix D is Schedule 3 with the modifications provided for by this Agreement.

99. The Company's changes to Schedule 7 proposed in its direct testimony shall be adopted except that the changes reflecting current ANSI standards shall not be made at this time and the words "meter maintenance and testing program" will remain. Attached as Appendix E is Schedule 7 with the modifications provided for by this Agreement.

100. The Company's changes to Schedule 10 proposed in its direct testimony shall be adopted except for the amendments described in Staff's direct testimony, which shall be interpreted as consistent with the current provisions of A.A.C. R14-2-1612. Attached as Appendix F is Schedule 10 with the modifications provided for by this Agreement.

101. Schedules 4 and 15 as set forth in APS' Application shall be approved. Appendix G is Schedule 4 with the modifications provided for by this Agreement. Appendix H is Schedule 15 with the modifications provided for by this Agreement.

102. The Commission may change the service schedules as a result of the ECAG or other similar process.

XV. Nuclear Decommissioning

103. Decommissioning costs shall be as proposed in APS' direct testimony. Attached as Appendix I is the level of decommissioning costs authorized and included in APS' total settlement test year revenue requirement.

XVI. Transmission Cost Adjustor

104. A transmission cost adjustor ("TCA") shall be established in order to ensure that any potential direct access customers will pay the same for transmission as standard offer customers. The TCA shall be limited to recovery (refund) of costs associated with changes in APS' open access transmission tariff ("OATT") or the tariff of an RTO or similar organization.

105. Whenever APS files an application with FERC to change its transmission rates, it shall file a notice with the Commission of its application. APS shall at the same time also provide a copy of its application to the Director of the Utilities Division.

106. The TCA shall not take effect until the transmission component of retail rates exceeds the test year base of $0.000476 per kWh by five percent. When this trigger amount is reached, APS may file for Commission approval of a TCA rate.

107. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the TCA shall operate.

XVII. Distributed Generation

108. Commission Staff shall schedule workshops to consider outstanding issues affecting distributed generation. Staff shall refer to the results of prior distributed generation workshops when determining the specific issues that will benefit from further study.

109 If necessary, the workshops may be followed with rulemaking.

XVIII. Bark Beetle Remediation

110. APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed test year levels of tree and brush control. The deferral account established for this purpose shall not accrue interest.

111. In the Company's next general rate proceeding, the Commission will determine the reasonableness, the prudence, and the appropriate allocation between distribution and transmission of these costs. The Commission will also determine an appropriate amortization period for the approved costs.

XIX. Rate Design

112. The rates set forth in this Agreement are designed to permit APS to recover an additional $67.5 million in base revenues as compared to adjusted test year base revenues.

113. APS' residential rate class will generate an additional 3.94% of base revenue compared with adjusted test year base revenue. Each bundled residential rate schedule will have the same basic structure (i.e., number and size of blocks, time-of-use time periods) as APS' existing base rates. Base rate levels shall recover the required revenue and shall permit cost-based unbundling of Distribution and Revenue Cycle Services, including Metering, Meter Reading, and Billing, to the degree practical.

114. Schedule E-10 and Schedule EC-1 will continue to be frozen and will not be eliminated in this proceeding. APS will provide notice to customers on these schedules that these rates will be eliminated in its next rate proceeding. Such notice shall be approved by Staff and shall be provided on these customers' bills at the conclusion of this proceeding and at the time that APS files its next rate case. E-10 and EC-1 will each generate an additional 4.82% of base revenue compared with adjusted test year base revenue.

115. Schedules E-12, ET-1, and ECT-1R will each generate an additional 3.8% of base revenue compared with adjusted test year base revenue.

116. APS will continue on-peak and off-peak rates for winter billing periods for all residential time-of-use customers served under Schedules ET-1 and ECT-1R. Within 180 days of a final decision in this proceeding, APS will submit a study to Staff that examines ways in which APS can implement more flexibility in changing APS' on- and off-peak time periods and other time-of-use characteristics, including making on-peak periods more reflective of the times of actual system peak. Before designing its study, APS shall consult with Staff to ensure that the study will address all relevant issues. Time-of-use issues will be reexamined in APS' next rate case.

117. APS' proposed experimental time-of-use periods for ET-1 and ECT-1R will be adopted. Annual reports evaluating the outcomes of adopting these additional time-of-use periods will be filed with Staff. The first report will be due 12 months from the date of a decision in this matter. The report shall make a recommendation regarding the continuation of the experimental time-of-use periods. Before preparing its report, APS shall consult with Staff to ensure that the report will address all relevant issues. These experimental time-of-use periods will be reexamined in APS' next rate case.

118. The existing 11:00 AM to 9:00 PM on-peak time periods shall remain for general service customers served on time-of-use schedules. The summer rate period shall begin with the first billing cycle in May and conclude with the last billing cycle in October. As part of APS' compliance filing, APS and Staff shall meet and confer to review the General Service schedules to ensure that they are consistent with the rate design principles set forth in this Agreement.

119. General Service rate schedules will be modified such that Schedules E-32, E-32R, E-34, E-35, E-53, E-54, and the contracts shown in the General Service section of the H schedules attached to APS' rate Application will each generate approximately 3.5% of additional base revenue compared with adjusted test year base revenue. The settlement rate designs for these rate schedules shall permit cost-based unbundling of Generation and Revenue Cycle Services, including Metering, Meter Reading, and Billing, to the degree practical. With regard to Schedules E-32, E-34, and E-35, the non-system-benefits revenue requirement assigned to the General Service class will be used to establish first the unbundled component of generation at cost and then the unbundled component of revenue cycle services at cost.

120. APS will establish an additional Primary Service Discount of $2.74/kW for military base customers served directly from APS substations.

121. Schedule E-32 has been modified in an effort to simplify the design, to make it more cost-based, and to smooth out the rate impact across customers of varying sizes within the rate schedule. Changes to Schedule E-32 include the addition of an energy block for customers with loads under 20 kW and an additional demand billing block for customers with loads greater than 100 kW. In addition, a time-of-use option will be made available to E-32 customers without restriction as to number of participants.

122. Schedules E-20, E-30, E-40, E-51, E-59 and E-67 will be increased by 5% compared to adjusted test year base revenue. Schedule E-20 shall be frozen. Schedules E-22, E-23 and E-24 will be frozen to new customers and will not be eliminated in this proceeding. APS will provide notice to customers on schedules E-21, E-22, E-23, and E-24 that these rates will be eliminated in APS' next rate proceeding. Such notice shall be approved by Staff and shall be provided on these customers' bills at the conclusion of this proceeding and at the time that APS files its next rate case. E-21, E-22, E-23, and E-24 will be increased by 5% compared to adjusted test year base revenue. Rate levels shall recover the required base revenue and permit cost-based unbundling of Generation and Revenue Cycle Services to the degree practical.

123. Frozen rates E-38 (Agricultural Irrigation Service) and E-38T (Agricultural Irrigation Service Time of Use option) will continue to be frozen and will not be eliminated in this proceeding. APS will provide notice to customers on these schedules that these rates will be eliminated in APS' next rate proceeding. Such notice shall be approved by Staff and shall be provided on these customers' bills at the conclusion of this proceeding and at the time that APS files its next rate case. Schedule E-38, Schedule E-38T, and Schedule E-221 (including options) will be increased to generate an additional 5% of base revenue compared with adjusted test year base revenue.

124. Dusk to Dawn Lighting (Schedule E-47) and Street Lighting Service (Schedule E-58) will be modified as proposed in APS' Application. Specific charges in these schedules will be increased to generate an additional 5% in base revenue compared with adjusted test year base revenue

125. Except as modified by this Agreement and to the extent not inconsistent with this Agreement, APS' rate design as proposed in its Application is adopted. As part of APS'

compliance filing, APS and Staff shall meet and confer to review APS' rate schedules to ensure that they are consistent with the rate design principles set forth in this Agreement.

126. The specific rate designs for each of the residential rate schedules and for general service rate schedules E-32, E-32 TOU, E-34, and E-35 are set forth in Appendix J. The remaining rates shall be filed by APS as otherwise provided for in this Agreement and in accordance with the compliance filing called for in paragraph 135.

XX. Litigation and Other Issues

127. Upon approval of this Agreement in accordance with Section XXI by a Commission order that is final and no longer subject to judicial review, APS shall dismiss with prejudice all of its appeals of Commission Decision No. 65154, the Track A order, and APS and its affiliates shall also dismiss any and all litigation related to Decision Nos. 65154 and 61973 and/or any alleged breach of contract.

128. Upon approval of this Agreement in accordance with Section XXI by a Commission order that is final and no longer subject to judicial review, APS and its affiliates shall forego any claim that APS, PWEC, Pinnacle West Capital Corporation ("PWCC"), or any of APS' affiliates were harmed by Commission Decision No. 65154.

129. Upon approval of this Agreement in accordance with Section XXI by a Commission order that is final and no longer subject to judicial review, the Preliminary Inquiry, ordered in Commission Decision No. 65796, shall be concluded with no further action by the Commission.

XXI. Commission Evaluation of Proposed Settlement

130. The Parties agree that all currently filed testimony and exhibits shall be accepted into the Commission's record as evidence.

131. The Parties recognize that Staff does not have the power to bind the Commission. For purposes of proposing a settlement agreement, Staff acts in the same manner as any party to a Commission proceeding.

132. This Agreement shall serve as a procedural device by which the Parties will submit their proposed settlement of APS' pending rate case, Docket No. E-01345A-03-0437, to the Commission. Except for paragraphs 9, 137, 138, 139, 140, and 143, this Agreement will not have any binding force or effect until its provisions are adopted as an order of the Commission.

133. The Parties further recognize that the Commission will independently consider and evaluate the terms of this Agreement.

134. If the Commission issues an order adopting all material terms of this Agreement, such action shall constitute Commission approval of the Agreement. Thereafter, the Parties shall abide by the terms as approved by the Commission.

135. Within sixty days after the Commission issues an order in this matter. APS shall file compliance tariffs for Staff review and approval. Subject to such review and approval, such compliance tariffs will become effective upon filing for billing cycles on and after that date.

136. If the Commission fails to issue an order adopting all material terms of this Agreement, any or all of the Parties may withdraw from this Agreement, and such Party or Parties may pursue without prejudice their respective remedies at law. For the purposes of this Agreement, whether a term is material shall be left to the discretion of the Party choosing to withdraw from the Agreement. If a Party withdraws from the Agreement pursuant to this paragraph and files an application for rehearing, the other Parties, except for Staff, shall support the application for rehearing by filing a document to that effect with the Commission. Staff shall not be obligated to file any document or take any position regarding the withdrawing Party's application for rehearing.

XXII. Miscellaneous Provisions

137. Nothing in this Agreement shall be construed as an admission by any of the Parties that any of the positions taken by any Party in this proceeding is unreasonable or unlawful. In addition, acceptance of this Agreement by any of the Parties is without prejudice to any position taken by any Party in these proceedings.

138. This Agreement represents the Parties' mutual desire to compromise and settle disputed issues in a manner consistent with the public interest. None of the positions taken in this Agreement by any of the Parties may be referred to, cited, or relied upon as precedent in any proceeding before the Commission, any other regulatory agency, or any court for any purpose except in furtherance of this Agreement.

139. This case presents a unique set of circumstances and has attracted a large number of participants with widely diverse interests. To achieve consensus for settlement, many participants are accepting positions that, in any other circumstances, they would be unwilling to accept. They are doing so because the Agreement, as a whole, with its various provisions for settling the unique issues presented by this case, is consistent with their long-term interests and with the broad public interest. The acceptance by any Party of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.

140. All negotiations relating to this Agreement are privileged and confidential. No Party is bound by any position asserted in negotiations, except as expressly stated in this Agreement. Evidence of conduct or statements made in the course of negotiating this Agreement shall not be admissible before this Commission, any other regulatory agency, or any court.

141. The "Definitive Text" of the Agreement shall be the text adopted by the Commission in an order that approves all material terms of the Agreement, including all modifications made by the Commission in such an order.

142. Each of the terms of the Definitive Text of the Agreement is in consideration and support of all other terms. Accordingly, the terms are not severable.

143. The Parties shall support and defend this Agreement before the Commission. Subject to paragraph 9, if the Commission adopts an order approving all material terms of this Agreement, the Parties will support and defend the Commission's order before any court or regulatory agency in which it may be at issue.

DATED this 18th day of August, 2004.

ARIZONA CORPORATION COMMISSION

By E.G. Johnson
Ernest G. Johnson
Director Utilities Division
1200 West Washington
Phoenix, AZ 85007

ARIZONA PUBLIC SERVICE COMPANY

By S M Wheeler
Steven M. Wheeler
Executive Vice President

RESIDENTIAL UTILIY CONSUMER OFFICE

By
Stephen Ahearn, Director

DECISION NO. 67744

STRATEGIC ENERGY, L.L.C.

By Andrew Washburn

Andrew Washburn
Interim President and Chief Financial Officer

WESTERN RESOURCE ADVOCATES

By______________________________

David Berry

~~Senior~~ Policy Advisor

P. O. Box 1064

Scottsdale, AZ 85252-1064

DECISION NO. 67744

ARIZONANS FOR ELECTRIC CHOICE
AND COMPETITION

By ______________________

Its President

DECISION NO. 67744

ARIZONA COMPETITIVE POWER ALLIANCE

By______________________________
Greg Patterson, Director

PHELPS DODGE MINING COMPANY

By Dennis Bonnert

Its Senior Vice President

DECISION NO. 67744

SOUTHWEST ENERGY EFFICIENCY PROJECT

By ______________________
Tim Hogan

DECISION NO. 67744

ARIZONA COMMUNITY ACTION ASSOCIATION

By Cynthia Z
Its Executive Director

ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION

By
Sean M. Seitz, President

TOWN OF WICKENBURG

By________________________________
Its________________________________

TOWN OF WICKENBURG IS MOVING TO WITHDRAW ITS INTERVENTION IN THIS DOCKET.

PPL SUNDANCE ENERGY, LLC

By________________________
Jay I. Moyes, Counsel

PPL SOUTHWEST GENERATION
HOLDINGS, LLC

By________________________
Jay I. Moyes, Counsel

DECISION NO. 67744

CONSTELLATION NEWENERGY, INC.

By ______________________________

Aaron Thomas, Vice President, West Region

FEDERAL EXECUTIVE AGENCIES

By______________________
Its Counsel
Allen G. Erickson, Major, USA

ARIZONA UTILITY INVESTORS ASSOCIATION

By Walter W. Meek

Its President

KROGER CO.

By Michael L. Kurtz

Its outside counsel

DECISION NO. 67744

BOWIE POWER STATION, LLC

By Tom C. Wray
Tom C. Wray, General Manger

SOUTHWESTERN POWER GROUP, II, LLC

By Tom C. Wray
Tom C. Wray, General Manager

MESQUITE POWER, L.L.C.

By Michael R. Niggli
Michael R. Niggli,
President

IBEW, AFL-CIO, CLC, LOCAL UNIONS 387, 640, AND 769

By________________ 8/17/04

Its Attorney

ARIZONA COGENERATION ASSOCIATION

By______________________________
Its______________________________

ARIZONA UTILITY INVESTORS ASSOCIATION

By______________________________
Its______________________________

SOUTHWESTERN POWER GROUP, II, L.L.C.

By______________________________
Its______________________________

BOWIE POWER STATION, L.L.C.

By______________________________
Its______________________________

IBEW, AFL-CIO, CLC, LOCAL UNIONS 387, 640, AND 769

By______________________________
Its______________________________

KROGER CO.

By______________________________
Its______________________________

DOME VALLEY ENERGY PARTNERS, L.L.C.

By V. L. Elafonte
Its Executive Vice President

MESQUITE POWER, L.L.C.

By______________________________
Its______________________________

DECISION NO. 67744

APPENDIX A

ARIZONA PUBLIC SERVICE
Depreciation Rate Summary
Related to Electric Plant at December 31, 2002

Depreciable Group			Depreciation Rate (A)	Service Life Rate (B)	Net Salvage Rate (C)
			A = (B + C)		
STEAM PRODUCTION PLANT					
FERC	311	Structures and Improvements	2.84%	2.37%	0.47%
FERC	312	Boiler Plant Equipment	3.50%	2.92%	0.58%
FERC	314	Turbogenerator Units	2.98%	2.49%	0.50%
FERC	315	Accessory Electric Equipment	2.70%	2.25%	0.45%
FERC	316	Miscellaneous Power Plant Equipment	4.14%	3.45%	0.69%
NUCLEAR PRODUCTION PLANT					
FERC	321	Structures and Improvements	2.60%	2.60%	0.00%
FERC	322	Reactor Plant Equipment	2.86%	2.80%	0.06%
FERC	322.1	Reactor Plant Equipment - Steam Generators	10.32%	8.82%	1.50%
FERC	323	Turbogenerator Units	2.90%	2.84%	0.06%
FERC	324	Accessory Electric Equipment	2.78%	2.73%	0.05%
FERC	325	Miscellaneous Power Plant Equipment	3.59%	3.52%	0.07%
OTHER PRODUCTION PLANT					
FERC	341	Structures and Improvements	2.69%	2.56%	0.13%
FERC	342	Fuel Holders, Products and Accessories	2.87%	2.74%	0.14%
FERC	343	Prime Movers	1.25%	1.25%	0.00%
FERC	344	Generators and Devices	3.38%	3.38%	0.00%
FERC	345	Accessory Electric Equipment	2.26%	2.26%	0.00%
FERC	346	Miscellaneous Power Plant Equipment	2.58%	2.58%	0.00%
TRANSMISSION PLANT (1)					
FERC	353	Station Equipment	1.52%	1.52%	0.00%
FERC	354	Towers and Fixtures	2.08%	1.54%	0.54%
FERC	356	Overhead Conductors and Devices	2.32%	1.72%	0.60%
		(1) Rates will apply to ACC Jurisdictional Assets in these Accounts			
DISTRIBUTION PLANT					
FERC	361	Structures and Improvements	2.10%	1.91%	0.19%
FERC	362	Station Equipment	2.04%	2.04%	0.00%
FERC	364	Poles, Towers and Fixtures - Wood	2.64%	2.40%	0.24%
FERC	364.1	Poles, Towers and Fixtures - Steel	2.03%	1.93%	0.10%
FERC	365	Overhead Conductors and Devices	1.99%	1.81%	0.18%
FERC	366	Underground Conduit	1.20%	1.14%	0.06%
FERC	367	Underground Conductors and Devices	3.18%	3.03%	0.15%
FERC	368	Line Transformers	2.30%	2.19%	0.11%
FERC	369	Services	2.60%	2.36%	0.24%
FERC	370	Meters	2.84%	2.84%	0.00%

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ARIZONA PUBLIC SERVICE
Depreciation Rate Summary
Related to Electric Plant at December 31, 2002

		Depreciable Group	Depreciation Rate (A) A = (B + C)	Service Life Rate (B)	Net Salvage Rate (C)
FERC	370.1	Electronic Meters	3.61%	3.61%	0.00%
FERC	371	Installations On Customers Premises	2.33%	1.94%	0.39%
FERC	373	Street Lighting and Signal Systems	3.10%	2.58%	0.52%
GENERAL PLANT					
FERC	390	Structures and Improvements	2.93%	2.55%	0.38%
FERC	391	Office Furniture and Equipment - Furniture	4.16%	4.16%	0.00%
FERC	391.1	Office Furniture and Equipment - PC Equipme	11.43%	11.43%	0.00%
FERC	391.2	Office Furniture and Equipment - Equipment	4.17%	4.17%	0.00%
FERC	393	Stores Equipment	0.00%	0.00%	0.00%
FERC	394	Tools, Shop and Garage Equipment	4.61%	4.61%	0.00%
FERC	395	Laboratory Equipment	5.07%	5.07%	0.00%
FERC	397	Communication Equipment	4.74%	4.74%	0.00%
FERC	398	Miscellaneous Equipment	3.85%	3.85%	0.00%

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ARIZONA PUBLIC SERVICE
Amortization Rate Summary
Related to Electric Plant at December 31, 2002

Amortization Group			Amortization Rate
INTANGIBLES			
FERC	301	Organization	0.00%
FERC	302	Franchise and Consents	4.00%
FERC	303L	PV Unit 2 Sale & Leaseback-Software	Over Life of lease
FERC	303	Misc Intangible-Contributed Plant	10.00%
FERC	303	Misc Intangible -Mexico Tie	20.00%
FERC	3031	Computer Software-5year life	20.00%
FERC	3032	Computer Software-10year life- Projects greater than $10 million	10.00%
PRODUCTION			
FERC	321-325	PV Unit 2 & Common-Sale & Leaseback	Over Life of lease
LAND RIGHTS			
FERC	3303	Limited Term Land Rights-Hydro Plants	Over Remaining Life of Plant
FERC	3503	Limited Term Land Rights-Transmission Lines	Over Life of Land Right
FERC	3503	Limited Term Land Rights-SCE	Over Life of Land Right
FERC	3603	Limited Term Land Rights-Distribution Lines	Over Life of Land Right
DISTRIBUTION PLANT			
FERC	361-368-371	Distribution Plant Leased Property	Over Life of Each Lease
GENERAL PLANT			
FERC	390	Buildings- Leasehold Improvements	Over Life of Each Lease
FERC	391	Capital Lease-Computer Equipment	Over Life of Each Lease
FERC	392	Capital Lease-Transportation Vehicles	Over Life of Each Lease
FERC	392	Transportation Vehicles	Depreciated by Vehicle Class(1)
FERC	396	Power Operated Equipment	Depreciated by Vehicle Class(1)
FERC	397	PV Common Sale & Lease Back	Over Life of Lease

(1) The depreciation study did not include accounts 392 or 396, therefore no changes are being proposed in this study. See attached schedule for rate by Vehicle Class.

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ARIZONA PUBLIC SERVICE COMPANY
PROPOSED AND CURRENTLY USED RATES

Transportation Equipment (392)

Class	Description	Proposed Rates for 2004	(1995) Current Rates
01	Passenger Sedans	15.00%	15.00%
03	Compact Autos	13.33%	13.33%
09	Compact Pickup	11.43%	11.43%
10	Commerical Vehicles to 5 Ton	9.25%	9.25%
11	Commerical Vehicles, 4-Wheel Drive	10.57%	10.57%
12	Conv. Dr. 5-10 Ton, Truck	7.50%	7.50%
13	Conv. Dr. 2 1/2 Ton w/Single-Person Aerial	7.27%	7.27%
14	4-Wheel Dr. 5-10 Ton, Truck	7.00%	7.00%
15	Conv. Dr. 10-15 Ton, Tractor, Dump Truck, Backhoe	5.38%	5.38%
16	Conv. Dr. 18-32 Ton, Line Construction with Aerial	5.33%	5.33%
17	4-Wheel Dr. 10-15 Ton, Truck	6.92%	6.92%
19	Trucks, 18-32 Ton, Tractor, Platform Dump, Hydrolift	5.83%	5.83%
22	Trucks, 15-25 Ton 6X6	6.54%	6.54%
26	Fork Lift, Electric, to 4,000#	6.67%	6.67%
27	Fork Lift, Gasoline, to 4,000#	4.69%	4.69%
28	Fork Lift, 8-10 Ton Capacity	6.67%	6.67%
29	Wheeled Backhoe/Loader & Backfiller	5.83%	5.83%
30	Motor Grader	10.00%	10.00%
32	D4 Caterpillar (Small)	7.50%	7.50%
35	Trailer, to 5,000# GVW	3.25%	3.25%
36	Trailer, 5,000-10,000# GVW	4.11%	4.11%
37	Trailer, 10,000-20,000# GVW	3.75%	3.75%
38	Trailer, 20,000-50,000# GVW	4.69%	4.69%
39	Trailer, Over 50,000# GVW	5.00%	5.00%
41	Trailer-Mounted Industrial Equipment	4.93%	4.93%
42	Mobile Crane 45 Ton	10.00%	10.00%

Note: The depreciation study did not include accounts 392 or 396, therefore no changes are being proposed.

ARIZONA PUBLIC SERVICE COMPANY
PROPOSED AND CURRENTLY USED RATES

Power Operated Equipment (396)

Class	Description	Proposed Rates for 2004	(1995) Current Rates
12	Conv. Dr. 5-10 Ton, Truck	7.50%	7.50%
13	Conv. Dr. 2 1/2 Ton w/Single-Person Aerial	7.27%	7.27%
14	4-Wheel Dr. 5-10 Ton, Truck	7.00%	7.00%
15	Conv. Dr. 10-15 Ton, Tractor, Dump Truck, Backhoe	5.38%	5.38%
16	Conv. Dr. 18-32 Ton, Line Construction with Aerial	5.33%	5.33%
17	4-Wheel Dr. 10-15 Ton, Truck	6.92%	6.92%
18	4-Wheel Dr. 15-20 Ton, Truck	6.92%	6.92%
19	Trucks, 18-32 Ton, Tractor, Platform Dump, Hydrolift	5.83%	5.83%
20	Truck, 18-32 Ton, Hole Digger, Hydrocrane & Carrier	7.00%	7.00%
22	Trucks, 15-25 Ton 6X6	6.54%	6.54%
23	Small Trencher	10.00%	10.00%
24	Medium Trencher	6.25%	6.25%
26	Fork Lift, Electric, to 4,000#	6.67%	6.67%
27	Fork Lift, Gasoline, to 4,000#	4.69%	4.69%
28	Fork Lift, 8-10 Ton Capacity	6.67%	6.67%
29	Wheeled Backhoe/Loader & Backfiller	5.83%	5.83%
30	Motor Grader	10.00%	10.00%
31	Snow Vehicles-Crawlers	10.00%	10.00%
32	D4 Caterpillar (Small)	7.50%	7.50%
33	D7 Caterpillar (Medium)	7.50%	7.50%
34	D8 Caterpillar (Heavy)	7.50%	7.50%
35	Trailer, to 5,000# GVW	3.25%	3.25%
38	Trailer, 20,000-50,000# GVW	4.69%	4.69%
40	Wire Tensioners	8.50%	8.50%
41	Trailer-Mounted Industrial Equipment	4.93%	4.93%
42	Mobile Crane 45 Ton	10.00%	10.00%

Note: The depreciation study did not include Accounts 392 and 396, therefore no changes are being proposed.

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PINNACLE WEST ENERGY CORPORATION
Depreciation Rate Summary
Related to Electric Plant at December 31, 2002

		Depreciable Group	Depreciation Rate (A) A = (B + C)	Service Life Rate (B)	Net Salvage Rate (C)
OTHER PRODUCTION					
FERC	341	Structures and Improvements	2.08%	1.98%	0.10%
FERC	342	Fuel Holders, Products & Accessories	2.14%	2.04%	0.10%
FERC	343	Prime Movers	2.14%	2.10%	0.04%
FERC	344	Generators and Devices	2.94%	2.86%	0.08%
TRANSMISSION					
FERC	353	Station Equipment	1.74%	1.74%	0
FERC	355	Poles and Fixtures - Steel	2.08%	1.81%	0.27%
FERC	356	Overhead Conductors and Devices	2.45%	1.81%	0.63%

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ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
PLANT IN SERVICE									
STEAM PRODUCTION PLANT									
311 Structures and Improvements									
Cholla Unit 1	06-2017	75 - S1.5	(20)	2,144,789	1,841,738	732,009	14.0	52,286	2.44%
Cholla Unit 2	06-2033	75 - S1.5	(20)	5,022,179	2,101,615	3,925,000	29.0	135,345	2.69%
Cholla Unit 3	06-2035	75 - S1.5	(20)	9,583,277	5,184,966	6,314,966	29.9	211,203	2.20%
Cholla Common	06-2035	75 - S1.5	(20)	36,234,550	19,318,431	24,163,029	29.9	808,128	2.23%
Four Corners Units 1-3	06-2016	75 - S1.5	(20)	15,972,927	10,628,079	8,539,433	13.3	642,063	4.02%
Four Corners Units 4-5	06-2031	75 - S1.5	(20)	9,195,585	5,124,992	5,909,710	26.8	220,512	2.40%
Four Corners Common	06-2031	75 - S1.5	(20)	3,946,871	2,227,796	2,508,449	26.8	93,599	2.37%
Navajo Units 1-3	06-2026	75 - S1.5	(20)	27,152,517	12,197,389	20,385,631	22.8	894,107	3.29%
Ocotillo Units 1-2	06-2020	75 - S1.5	(20)	3,787,972	2,084,288	2,461,278	17.1	143,934	3.80%
Saguaro Units 1-2	06-2014	75 - S1.5	(20)	2,446,832	1,989,759	946,439	11.3	83,756	3.42%
Yucca Unit 1	06-2016	75 - S1.5	(20)	462,567	452,608	102,472	13.1	7,822	1.69%
Total Account 311				115,950,066	63,151,661	75,988,418		3,292,754	2.84%
312 Boiler Plant Equipment									
Cholla Unit 1	06-2017	48 - L2	(20)	26,431,681	17,605,653	14,112,364	13.4	1,053,162	3.98%
Cholla Unit 2	06-2033	48 - L2	(20)	140,612,492	86,692,363	82,042,627	22.0	3,729,210	2.65%
Cholla Unit 3	06-2035	48 - L2	(20)	100,448,965	60,203,467	60,335,291	22.9	2,634,729	2.62%
Cholla Common	06-2035	48 - L2	(20)	22,626,051	11,328,185	15,823,076	24.8	638,027	2.82%
Four Corners Units 1-3	06-2016	48 - L2	(20)	197,139,757	115,304,816	121,262,892	12.7	9,548,259	4.84%
Four Corners Units 4-5	06-2031	48 - L2	(20)	111,591,873	64,306,071	69,604,177	22.1	3,149,510	2.82%
Four Corners Common	06-2031	48 - L2	(20)	3,290,391	2,152,160	1,796,309	22.8	78,785	2.39%
Navajo Units 1-3	06-2026	48 - L2	(20)	149,350,243	69,950,378	109,269,914	20.6	5,304,365	3.55%
Ocotillo Units 1-2	06-2020	48 - L2	(20)	24,152,351	17,905,382	11,077,439	15.2	728,779	3.02%
Saguaro Units 1-2	06-2014	48 - L2	(20)	24,387,712	16,566,160	12,699,094	11.1	1,144,063	4.69%
Total Account 312				800,031,516	462,014,635	498,023,184		28,008,889	3.50%
314 Turbogenerator Units									
Cholla Unit 1	06-2017	65 - R2	(20)	10,417,373	7,459,687	5,041,161	14.0	360,083	3.46%
Cholla Unit 2	06-2033	65 - R2	(20)	28,551,889	15,518,951	18,743,316	27.5	681,575	2.39%
Cholla Unit 3	06-2035	65 - R2	(20)	39,626,197	16,959,280	30,592,156	29.7	1,030,039	2.60%
Cholla Common	06-2035	65 - R2	(20)	631,278	335,591	421,943	29.0	14,550	2.30%
Four Corners Units 1-3	06-2016	65 - R2	(20)	36,412,926	24,829,283	18,866,228	13.1	1,440,170	3.96%
Four Corners Units 4-5	06-2031	65 - R2	(20)	14,488,238	7,086,302	10,299,584	26.3	391,619	2.70%
Four Corners Common	06-2031	65 - R2	(20)	1,726,164	1,349,968	721,429	23.3	30,963	1.79%
Navajo Units 1-3	06-2026	65 - R2	(20)	24,387,110	14,479,672	14,784,860	22.0	672,039	2.76%
Ocotillo Units 1-2	06-2020	65 - R2	(20)	15,517,601	11,437,238	7,183,883	16.8	427,612	2.76%
Saguaro Units 1-2	06-2014	65 - R2	(20)	16,259,698	13,244,927	6,266,711	11.2	559,528	3.44%

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
	Total Account 314				188,018,474	112,700,899	112,921,270		5,608,177	2.98%
315	Accessory Electric Equipment									
	Cholla Unit 1	06-2017	60 - R2.5	(20)	4,756,906	3,592,717	2,115,570	13.9	152,199	3.20%
	Cholla Unit 2	06-2033	60 - R2.5	(20)	42,235,618	25,070,631	25,612,111	26.8	955,676	2.26%
	Cholla Unit 3	06-2035	60 - R2.5	(20)	29,917,206	16,267,820	19,632,827	28.5	688,871	2.30%
	Cholla Common	06-2035	60 - R2.5	(20)	4,476,001	2,380,788	2,990,413	28.7	104,196	2.33%
	Four Corners Units 1-3	06-2016	60 - R2.5	(20)	16,353,282	9,525,599	10,098,339	13.2	765,026	4.68%
	Four Corners Units 4-5	06-2031	60 - R2.5	(20)	9,183,206	5,039,778	5,980,069	25.9	230,891	2.51%
	Four Corners Common	06-2031	60 - R2.5	(20)	2,596,719	2,104,631	1,011,432	21.0	48,163	1.85%
	Navajo Units 1-3	06-2026	60 - R2.5	(20)	20,226,184	11,727,970	12,543,463	22.0	570,157	2.82%
	Ocotillo Units 1-2	06-2020	60 - R2.5	(20)	2,407,622	2,023,821	865,325	16.3	53,087	2.20%
	Saguaro Units 1-2	06-2014	60 - R2.5	(20)	2,654,661	2,355,021	830,572	11.2	74,158	2.79%
	Total Account 315				134,807,415	80,088,776	81,680,122		3,642,425	2.70%
316	Miscellaneous Power Plant Equipment									
	Cholla Unit 1	06-2017	40 - R2	(20)	2,315,189	1,189,333	1,588,894	13.5	117,696	5.08%
	Cholla Unit 2	06-2033	40 - R2	(20)	4,846,431	2,631,492	3,184,225	22.1	144,083	2.97%
	Cholla Unit 3	06-2035	40 - R2	(20)	4,138,531	1,990,199	2,976,038	23.8	125,044	3.02%
	Cholla Common	06-2035	40 - R2	(20)	7,098,069	2,439,747	6,075,536	25.8	235,486	3.32%
	Four Corners Units 1-3	06-2016	40 - R2	(20)	4,330,612	925,502	4,271,232	13.1	326,048	7.53%
	Four Corners Units 4-5	06-2031	40 - R2	(20)	3,304,340	1,402,561	2,562,647	23.0	111,419	3.37%
	Four Corners Common	06-2031	40 - R2	(20)	8,133,224	3,483,659	6,276,210	23.2	270,526	3.33%
	Navajo Units 1-3	06-2026	40 - R2	(20)	11,805,250	5,248,830	8,917,470	20.2	441,459	3.74%
	Ocotillo Units 1-2	06-2020	40 - R2	(20)	3,711,192	1,301,603	3,151,827	16.2	194,557	5.24%
	Saguaro Units 1-2	06-2014	40 - R2	(20)	3,191,024	1,340,385	2,488,844	10.9	228,334	7.16%
	Yucca Unit 1	06-2016	40 - R2	(20)	452,868	359,801	183,641	12.2	15,053	3.32%
	Total Account 316				53,324,730	22,313,112	41,676,564		2,209,705	4.14%
	TOTAL STEAM PRODUCTION PLANT				**1,292,132,201**	**740,269,083**	**810,289,558**		**42,761,950**	
	NUCLEAR PRODUCTION PLANT									
321	Structures and Improvements									
	Palo Verde Unit 1	12-2024	65 - R2.5	0	161,039,432	69,557,944	91,481,488	21.2	4,315,165	2.68%
	Palo Verde Unit 2	12-2025	65 - R2.5	0	88,415,270	38,859,061	49,556,209	22.0	2,252,555	2.55%
	Palo Verde Unit 3	03-2027	65 - R2.5	0	159,591,077	63,133,223	96,457,854	23.3	4,139,822	2.59%
	Palo Verde Water Reclamati	03-2027	65 - R2.5	0	125,593,913	51,122,827	74,471,086	23.2	3,209,961	2.56%
	Palo Verde Common	03-2027	65 - R2.5	0	98,127,309	39,316,906	58,810,403	23.2	2,534,931	2.58%
	Total Account 321				632,767,001	261,989,961	370,777,040		16,452,433	2.60%
322	Reactor Plant Equipment									
	Palo Verde Unit 1	12-2024	70 - R1	(2)	359,545,213	153,616,828	213,119,289	20.6	10,345,597	2.88%

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
	Palo Verde Unit 2	12-2025	70 - R1	(2)	176,362,235	72,582,559	107,306,921	21.5	4,991,020	2.83%
	Palo Verde Unit 3	03-2027	70 - R1	(2)	322,750,700	121,218,478	207,987,236	22.6	9,202,975	2.85%
	Palo Verde Water Reclamati	03-2027	70 - R1	(2)	123,313	7,176	118,603	23.0	5,157	4.18%
	Palo Verde Common	03-2027	70 - R1	(2)	26,449,873	9,583,436	17,395,434	22.6	769,709	2.91%
	Total Account 322				885,231,334	357,008,477	545,927,484		25,314,457	2.86%
322.1	Reactor Plant Equipment - Steam Generators									
	Palo Verde Unit 1	12-2005	Square	(17)	30,722,375	27,569,149	8,376,030	3.0	2,792,010	9.09%
	Palo Verde Unit 2	12-2003	Square	(17)	15,870,053	15,868,635	2,699,327	1.0	2,699,327	17.01%
	Palo Verde Unit 3	12-2007	Square	(17)	25,413,317	20,039,935	9,693,646	5.0	1,938,729	7.63%
	Total Account 322.1				72,005,745	63,477,719	20,769,003		7,430,066	10.32%
323	Turbogenerator Units									
	Palo Verde Unit 1	12-2024	60 - S0	(2)	117,808,078	51,570,896	68,593,344	19.9	3,446,902	2.93%
	Palo Verde Unit 2	12-2025	60 - S0	(2)	76,754,224	32,432,468	45,856,840	20.8	2,204,656	2.87%
	Palo Verde Unit 3	03-2027	60 - S0	(2)	142,895,088	55,838,987	89,914,003	21.8	4,124,496	2.89%
	Palo Verde Water Reclamati	03-2027	60 - S0	(2)	217,707	76,585	145,476	22.0	6,613	3.04%
	Palo Verde Common	03-2027	60 - S0	(2)	1,223,879	346,554	901,803	22.2	40,622	3.32%
	Total Account 323				338,898,976	140,265,490	205,411,466		9,823,287	2.90%
324	Accessory Electric Equipment									
	Palo Verde Unit 1	12-2024	45 - R3	(2)	115,495,170	53,444,066	64,361,007	20.0	3,218,050	2.79%
	Palo Verde Unit 2	12-2025	45 - R3	(2)	50,119,388	21,982,186	29,139,590	20.9	1,394,239	2.78%
	Palo Verde Unit 3	03-2027	45 - R3	(2)	89,143,623	36,343,481	54,583,014	22.1	2,469,820	2.77%
	Palo Verde Common	03-2027	45 - R3	(2)	17,918,193	7,299,463	10,977,094	22.0	498,959	2.78%
	Total Account 324				272,676,374	119,069,196	159,060,705		7,581,068	2.78%
325	Miscellaneous Power Plant Equipment									
	Palo Verde Unit 1	12-2024	35 - R0.5	(2)	29,671,405	11,770,905	18,493,928	17.7	1,044,855	3.52%
	Palo Verde Unit 2	12-2025	35 - R0.5	(2)	26,389,406	8,702,844	18,214,350	18.7	974,029	3.69%
	Palo Verde Unit 3	03-2027	35 - R0.5	(2)	27,284,046	9,445,478	18,384,249	19.2	957,513	3.51%
	Palo Verde Water Reclamati	03-2027	35 - R0.5	(2)	88,819	27,706	62,889	19.5	3,225	3.63%
	Palo Verde Common	03-2027	35 - R0.5	(2)	48,459,510	15,382,218	34,046,482	19.4	1,754,973	3.62%
	Total Account 325				131,893,186	45,329,151	89,201,899		4,734,595	3.59%
	TOTAL NUCLEAR PRODUCTION PLANT				**2,333,472,616**	**987,139,994**	**1,391,147,596**		**71,335,907**	
	HYDRO PRODUCTION PLANT									
331	Structures and Improvement	12-2004	200-SQ	0	100,878	100,878	0	0.0	0	0.00
332	Reservoirs, Dams and Water	12-2004	200-SQ	0	991,936	1,105,086	(113,150)	0.0	0	0.00

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ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	
333	Water Wheels, Turbines and	12-2004	200-SQ	0	157,196	157,196	0	0.0	0	0.00	
334	Accessory Electric Equipmer	12-2004	200-SQ	0	627,611	627,611	0	0.0	0	0.00	
335	Miscellaneous Power Plant E	12-2004	200-SQ	0	126,018	126,018	0	0.0	0	0.00	
336	Roads, Railroads and Bridge	12-2004	200-SQ	0	77,427	77,427	0	0.0	0	0.00	
	Hydro Decomissioning Costs				-	7,864,531	5,335,469	2.0	2,667,735		
	TOTAL HYDRO PRODUCTION PLANT				2,081,068	10,058,747	5,222,319		2,667,735		
	OTHER PRODUCTION PLANT										
341	Structures and Improvements										
	Douglas CT	06-2017	80 - S1	(5)	4,562	4,148	642	13.9	46	1.01%	
	Ocotillo CT 1 - 2	06-2017	80 - S1	(5)	328,749	230,819	114,367	14.5	7,887	2.40%	
	Saguaro CT	06-2017	80 - S1	(5)	1,288,525	466,971	885,980	14.4	61,526	4.77%	
	Solar Unit 1		12 - SQ	0	375,512	383,809	(8,297)	3.6	0	0.00%	(2)
	West Phoenix CT 1 - 2	06-2017	80 - S1	(5)	510,951	419,492	117,007	14.2	8,240	1.61%	
	West Phoenix Combined Cy	06-2031	80 - S1	(5)	6,706,722	2,438,522	4,603,536	28.1	163,827	2.44%	
	Yucca CT 1 - 4	06-2016	80 - S1	(5)	452,751	222,815	252,574	13.4	18,849	4.16%	
	Total Account 341				9,667,772	4,166,576	5,965,809		260,376	2.69%	
342	Fuel Holders, Products and Accessories										
	Douglas CT	06-2017	70 - S1	(5)	137,759	100,065	44,582	14.0	3,184	2.31%	
	Ocotillo CT 1 - 2	06-2017	70 - S1	(5)	719,859	517,984	237,868	14.0	16,991	2.36%	
	Saguaro CT	06-2017	70 - S1	(5)	1,304,977	1,019,500	350,726	14.0	25,052	1.92%	
	West Phoenix CT 1 - 2	06-2017	70 - S1	(5)	1,437,533	1,123,270	386,140	14.0	27,581	1.92%	
	West Phoenix Combined Cy	06-2031	70 - S1	(5)	19,343,993	2,649,135	17,662,058	27.7	637,619	3.30%	
	Yucca CT 1 - 4	06-2016	70 - S1	(5)	3,232,217	2,859,228	534,600	12.9	41,442	1.28%	
	Total Account 342				26,176,338	8,269,182	19,215,973		751,870	2.87%	
343	Prime Movers										
	Douglas CT	06-2017	70 - L1.5	0	1,101,449	999,227	102,222	14.2	7,199	0.65%	(1)
	Ocotillo CT 1 - 2	06-2017	70 - L1.5	0	6,679,324	5,679,469	999,855	14.1	70,912	1.06%	
	Saguaro CT	06-2017	70 - L1.5	0	8,102,651	6,657,234	1,445,417	13.8	104,740	1.29%	
	West Phoenix CT 1 - 2	06-2017	70 - L1.5	0	8,802,636	6,220,272	2,582,364	14.2	181,857	2.07%	
	Yucca CT 1 - 4	06-2016	70 - L1.5	0	7,920,584	7,302,457	618,127	14.2	43,530	0.55%	(1)
	Total Account 343				32,606,644	26,858,659	5,747,985		408,237	1.25%	
344	Generators and Devices										
	Douglas CT	06-2017	37 - R3	0	551,765	542,840	8,925	9.7	920	0.17%	
	Ocotillo CT 1 - 2	06-2017	37 - R3	0	6,402,044	3,500,409	2,901,635	13.6	213,356	3.33%	
	Saguaro CT	06-2017	37 - R3	0	4,185,247	2,504,957	1,680,290	13.0	129,253	3.09%	
	Solar Unit 1		12 - SQ	0	6,933,081	3,289,918	3,643,163	7.8	467,072	6.74%	
	West Phoenix CT 1 - 2	06-2017	37 - R3	0	4,115,901	3,202,560	913,341	12.3	74,255	1.80%	

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Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
	West Phoenix Combined Cy(	06-2031	37 - R3	(2)	81,920,222	11,983,119	71,575,507	26.2	2,731,890	3.33%
	Yucca CT 1 - 4	06-2016	37 - R3	0	5,395,818	4,370,148	1,025,670	11.6	88,420	1.64%
	Total Account 344				109,504,078	29,393,951	81,748,531		3,705,166	3.38%
345	Accessory Electric Equipment									
	Douglas CT	06-2017	50 - S2	0	353,277	313,549	39,728	13.1	3,033	0.86%
	Ocotillo CT 1 - 2	06-2017	50 - S2	0	1,494,636	1,281,843	212,793	13.2	16,121	1.08%
	Saguaro CT	06-2017	50 - S2	0	1,715,774	1,389,500	326,274	13.4	24,349	1.42%
	Solar Unit 1		12 - SQ	0	169,527	40,179	129,348	9.9	13,065	7.71%
	West Phoenix CT 1 - 2	06-2017	50 - S2	0	1,557,744	1,315,426	242,318	13.2	18,357	1.18%
	West Phoenix Combined Cy(	06-2031	50 - S2	0	11,925,645	2,562,942	9,362,703	27.8	336,788	2.82%
	Yucca CT 1 - 4	06-2016	50 - S2	0	2,166,526	1,817,969	348,557	13.0	26,812	1.24%
	Total Account 345				19,383,129	8,721,408	10,661,721		438,525	2.26%
346	Miscellaneous Power Plant Equipment									
	Douglas CT	06-2017	70 - L1	0	40,913	30,160	10,753	13.8	779	1.90%
	Ocotillo CT 1 - 2	06-2017	70 - L1	0	553,173	418,696	134,477	14.0	9,606	1.74%
	Saguaro CT	06-2017	70 - L1	0	790,906	410,357	380,549	14.1	26,989	3.41%
	West Phoenix CT 1 - 2	06-2017	70 - L1	0	957,431	508,533	448,898	14.1	31,837	3.33%
	West Phoenix Combined Cy(	06-2031	70 - L1	0	2,608,877	895,856	1,713,021	26.6	64,399	2.47%
	Yucca CT 1 - 4	06-2016	70 - L1	0	427,175	357,633	69,542	13.2	5,268	1.23%
	Total Account 346				5,378,475	2,621,235	2,757,240		138,878	2.58%
TOTAL OTHER PRODUCTION PLANT					**202,716,436**	**80,031,011**	**126,097,259**		**5,703,052**	

(1) Staff's reallocation of reserves caused account to have a remaining Net Book Value. APS selected the longest life of other plant in that FERC account to calculate remaining life.
(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
TRANSMISSION PLANT										
352	Structures and Improvements		50 - R4	(5)	27,618,299	12,484,016	16,515,198	35.2	469,182	1.70%
352.5	Structures and Improvements - SCE 500 KV Line				409,725	424,897	(15,172)		13,316	3.25% (a)
353	Station Equipment		57 - R1.5	0	428,736,305	130,140,054	298,596,251	45.7	6,538,127	1.52%
353.5	Station Equipment - SCE 500 I				7,747,282	7,349,363	397,919		251,787	3.25% (a)
354	Towers and Fixtures		60 - R3	(35)	83,464,531	46,097,366	66,579,751	38.3	1,738,375	2.08%
354.5	Towers and Fixtures - SCE 50(				13,752,584	17,477,965	(3,725,381)		446,959	3.25% (a)
355	Poles and Fixtures - Wood		48 - R1.5	(35)	91,126,939	27,541,958	95,479,410	38.5	2,479,985	2.72%
355.1	Poles and Fixtures - Steel		55 - R3	(15)	83,067,888	22,833,440	72,694,631	45.1	1,611,854	1.94%
355.5	Poles and Fixtures - SCE 500 I				930,308	692,575	237,733		30,235	3.25% (a)
356	Overhead Conductors and Dev		55 - R3	(35)	205,771,417	94,269,666	183,521,747	38.5	4,766,799	2.32%
356.5	Overhead Conductors and Devices - SCE 500 KV Line				22,653,515	28,947,611	(6,294,096)		736,239	3.25% (a)
357	Underground Conduit		48 - S1.5	(10)	10,444,362	4,087,064	7,401,734	35.7	207,331	1.99%
358	Underground Conductors and I		40 - R3	(10)	18,551,254	9,702,854	10,703,525	26.3	406,978	2.19%

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)	
	TOTAL TRANSMISSION PLANT				994,274,409	402,048,829	742,093,250		19,697,167		
DISTRIBUTION PLANT											
361	Structures and Improvements		45 - R2.5	(10)	25,815,042	10,429,908	17,966,638	33.1	542,799	2.10%	
362	Station Equipment		44 - L0.5	0	212,357,577	52,722,295	159,635,282	36.9	4,332,029	2.04%	
364	Poles, Towers and Fixtures - W		38 - R0.5	(10)	284,200,711	81,128,434	231,492,348	30.9	7,491,662	2.64%	
364.1	Poles, Towers and Fixtures - S		50 - R3	(5)	53,919,651	5,601,820	51,013,814	46.6	1,094,717	2.03%	
365	Overhead Conductors and Dev		53 - O1	(10)	218,856,780	33,437,453	207,305,005	47.7	4,346,017	1.99%	
366	Underground Conduit		86 - O1	(5)	425,723,116	26,924,767	420,084,505	82.4	5,098,113	1.20%	
367	Underground Conductors and I		29 - L1	(5)	805,505,783	258,865,205	586,915,867	22.9	25,629,514	3.18%	
368	Line Transformers		36 - R3	(5)	486,837,053	235,537,009	275,641,897	24.6	11,204,955	2.30%	
369	Services		37 - S2	(10)	242,404,812	91,086,515	175,558,778	27.9	6,292,429	2.60%	
370	Meters		29 - L0	0	91,330,710	34,836,184	56,494,526	21.8	2,596,256	2.84%	
370.1	Electronic Meters		26 - R1.5	0	54,691,249	8,612,961	46,078,288	23.3	1,975,913	3.61%	
371	Installations On Customers Pre		50 - O2	(20)	25,335,831	3,863,126	26,539,871	45.0	589,775	2.33%	
373	Street Lighting and Signal Syst		35 - R2	(20)	57,185,737	22,716,125	45,906,759	25.9	1,772,462	3.10%	
	TOTAL DISTRIBUTION PLANT				2,984,164,052	865,761,802	2,300,633,578		72,966,640		
GENERAL PLANT											
390	Structures and Improvements		39 - R1	(15)	96,667,435	24,085,116	87,082,434	30.7	2,836,561	2.93%	
391	Office Furniture and Equipmen		20 - SQ	0	19,919,640	11,543,613	8,376,027	10.1	829,310	4.16%	
391.1	Office Furniture and Equipmen		8 - R3	0	38,654,946	15,103,632	23,551,314	5.3	4,418,633	11.43%	
391.2	Office Furniture and Equipmen		22 - R4	0	7,652,923	2,932,191	4,720,732	14.8	318,968	4.17%	
393	Stores Equipment		20 - SQ	0	1,227,371	1,235,746	(8,375)	2.8	0	0.00%	(2)
394	Tools, Shop and Garage Equip		20 - SQ	0	12,673,031	4,673,542	7,999,489	13.7	583,904	4.61%	
395	Laboratory Equipment		20 - L1	0	1,350,583	531,270	819,313	12.0	68,504	5.07%	
397	Communication Equipment		19 - S1.5	0	94,309,691	40,677,647	53,632,044	12.0	4,469,337	4.74%	
398	Miscellaneous Equipment		24 - S1.5	0	1,336,404	481,755	854,649	16.6	51,454	3.85%	
	TOTAL GENERAL PLANT				273,792,024	101,264,512	187,027,627		13,576,672		
	TOTAL DEPRECIABLE PLANT STUDIED				8,082,632,804	3,186,573,978	5,562,511,188		228,709,123		

(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

(a) Assets related to the 500 KV SCE Transmission Line are Depreciated at a rate of 3.25%.

	STEAM PRODUCTION PLANT NOT STUDIED	Original Cost at 12/31/02	Book Accumulated Depreciation
311	Structures and Improvements - West Phoenix	0	80,895
312	Boiler Plant Equipment - West Phoenix Units	0	300,097
312	Boiler Plant Equipment - Yucca Unit 1	425,323	441,994
314	Turbogenerator Units - West Phoenix Units 4	0	314,512
314	Turbogenerator Units - Yucca Unit 1	184,916	188,319

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
315	Accessory Electric Equipment - West Phoenix				33,968	83,338				
315	Accessory Electric Equipment - Yucca Unit 1				182,084	185,435				
316	Misc. Power Plant Equipment-West Phoenix U				17,267	0				
TOTAL STEAM PRODUCTION PLANT NOT STUDIED					843,558	1,594,590				
GENERAL PLANT NOT STUDIED										
392	Vehicles				28,410,886	20,605,998				
396	Power Operated Equipment				27,947,651	18,603,989				
TOTAL GENERAL PLANT NOT STUDIED					56,358,537	39,209,987				
OTHER PROPERTY NOT STUDIED										
Intangible Plant										
301	Organization				73,639					
302	Franchises and Consents				883,584					
303	Miscellaneous Intangible Plant				201,550,375					
Leased Property										
321	Structures and Improvements				1,633,193					
322	Reactor Plant Equipment				9,670,223					
323	Turbogenerator Units				2,705,885					
324	Accessory Electric Equipment				944,788					
325	Miscellaneous Power Plant Equipment				563,135					
361	Structures and Improvements				195,512					
368	Line Transformers				179,394					
371	Installations On Customers Premises				60,386					
390	Structures and Improvements				11,160,324					
397	Communication Equipment				245,938					
TOTAL OTHER PROPERTY NOT STUDIED					229,866,377	120,727,768				
TOTAL DEPRECIABLE PLANT IN SERVICE					8,369,701,276	3,348,106,323				
NONDEPRECIABLE PLANT										
310	Land and Land Rights				3,295,288					
320	Land and Land Rights				3,399,728					
330	Land and Land Rights				64,500					
340	Land and Land Rights				28,192					
350	Land and Land Rights				50,808,274					
360	Land and Land Rights				26,755,119					
389	Land and Land Rights				7,327,436					
TOTAL NONDEPRECIABLE					91,678,517					
TOTAL PLANT IN SERVICE					8,461,379,793					

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1 Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)	Annual Accrual Service Life Amount (11) = (9)*100/(100+(-4))	Annual Accrual Service Life Rate (12)=(11)/(5)	Annual Accrual Net Salvage Amount (13) = (9)*(-4)/100+(-4)	Annual Accrual Net Salvage Rate (14)=(13)/(5)
PLANT IN SERVICE													
STEAM PRODUCTION PLANT													
311 Structures and Improvements													
Cholla Unit 1	06-2017	75 - S1.5	(20)	2,144,789	1,841,738	732,009	14.0	52,286	2.44%	$43,572	2.03%	$8,714	0.41%
Cholla Unit 2	06-2033	75 - S1.5	(20)	5,022,179	2,101,615	3,925,000	29.0	135,345	2.69%	112,787	2.25%	22,557	0.45%
Cholla Unit 3	06-2035	75 - S1.5	(20)	9,583,277	5,184,966	6,314,966	29.9	211,203	2.20%	176,002	1.84%	35,200	0.37%
Cholla Common	06-2035	75 - S1.5	(20)	36,234,550	19,318,431	24,163,029	29.9	808,128	2.23%	673,440	1.86%	134,688	0.37%
Four Corners Units 1-3	06-2016	75 - S1.5	(20)	15,972,927	10,628,079	8,539,433	13.3	642,063	4.02%	535,052	3.35%	107,010	0.67%
Four Corners Units 4-5	06-2031	75 - S1.5	(20)	9,195,585	5,124,992	5,909,710	26.8	220,512	2.40%	183,760	2.00%	36,752	0.40%
Four Corners Common	06-2031	75 - S1.5	(20)	3,946,871	2,227,796	2,508,449	26.8	93,599	2.37%	77,999	1.98%	15,600	0.40%
Navajo Units 1-3	06-2026	75 - S1.5	(20)	27,152,517	12,197,389	20,385,631	22.8	894,107	3.29%	745,089	2.74%	149,018	0.55%
Ocotillo Units 1-2	06-2020	75 - S1.5	(20)	3,787,972	2,084,288	2,461,278	17.1	143,934	3.80%	119,945	3.17%	23,989	0.63%
Saguaro Units 1-2	06-2014	75 - S1.5	(20)	2,448,832	1,989,759	946,439	11.3	83,756	3.42%	69,796	2.85%	13,959	0.57%
Yucca Unit 1	06-2016	75 - S1.5	(20)	462,567	452,608	102,472	13.1	7,822	1.69%	6,519	1.41%	1,304	0.28%
Total Account 311				115,950,066	63,151,661	75,988,418		3,292,754	2.84%	2,743,962	2.37%	548,792	0.47%
312 Boiler Plant Equipment													
Cholla Unit 1	06-2017	48 - L2	(20)	26,431,681	17,605,653	14,112,364	13.4	1,053,162	3.98%	877,635	3.32%	175,527	0.66%
Cholla Unit 2	06-2033	48 - L2	(20)	140,612,492	86,892,363	82,042,627	22.0	3,729,210	2.65%	3,107,675	2.21%	621,535	0.44%
Cholla Unit 3	06-2035	48 - L2	(20)	100,448,965	60,203,467	60,335,291	22.9	2,634,729	2.62%	2,195,607	2.19%	439,121	0.44%
Cholla Common	06-2035	48 - L2	(20)	22,626,051	11,328,185	15,823,076	24.8	638,027	2.82%	531,689	2.35%	106,338	0.47%
Four Corners Units 1-3	06-2016	48 - L2	(20)	197,139,757	115,304,816	121,262,892	12.7	9,548,259	4.84%	7,956,883	4.04%	1,591,377	0.81%
Four Corners Units 4-5	06-2031	48 - L2	(20)	111,591,873	64,306,071	69,604,177	22.1	3,149,510	2.82%	2,624,592	2.35%	524,918	0.47%
Four Corners Common	06-2031	48 - L2	(20)	3,290,391	2,152,160	1,796,309	22.8	78,785	2.39%	65,655	2.00%	13,131	0.40%
Navajo Units 1-3	06-2026	48 - L2	(20)	149,350,243	69,950,378	109,269,914	20.6	5,304,365	3.55%	4,420,304	2.96%	884,061	0.59%
Ocotillo Units 1-2	06-2020	48 - L2	(20)	24,152,351	17,905,382	11,077,439	15.2	728,779	3.02%	607,316	2.51%	121,463	0.50%
Saguaro Units 1-2	06-2014	48 - L2	(20)	24,387,712	16,566,160	12,699,094	11.1	1,144,063	4.69%	953,385	3.91%	190,677	0.78%
Total Account 312				800,031,516	462,014,635	498,023,184		28,008,889	3.50%	23,340,741	2.92%	4,668,148	0.58%
314 Turbogenerator Units													
Cholla Unit 1	06-2017	65 - R2	(20)	10,417,373	7,459,687	5,041,161	14.0	360,083	3.46%	300,069	2.88%	60,014	0.58%
Cholla Unit 2	06-2033	65 - R2	(20)	28,551,889	15,518,951	18,743,316	27.5	681,575	2.39%	567,979	1.99%	113,596	0.40%
Cholla Unit 3	06-2035	65 - R2	(20)	39,626,197	16,959,280	30,592,156	29.7	1,030,039	2.60%	858,366	2.17%	171,673	0.43%
Cholla Common	06-2035	65 - R2	(20)	631,278	335,591	421,943	29.0	14,550	2.30%	12,125	1.92%	2,425	0.38%
Four Corners Units 1-3	06-2016	65 - R2	(20)	36,412,926	24,829,283	18,866,228	13.1	1,440,170	3.96%	1,200,142	3.30%	240,028	0.66%
Four Corners Units 4-5	06-2031	65 - R2	(20)	14,488,238	7,086,302	10,299,584	26.3	391,619	2.70%	326,349	2.25%	65,270	0.45%
Four Corners Common	06-2031	65 - R2	(20)	1,726,164	1,349,968	721,429	23.3	30,963	1.79%	25,802	1.49%	5,160	0.30%
Navajo Units 1-3	06-2026	65 - R2	(20)	24,387,110	14,479,672	14,784,860	22.0	672,039	2.76%	560,033	2.30%	112,007	0.46%
Ocotillo Units 1-2	06-2020	65 - R2	(20)	15,517,601	11,437,238	7,183,883	16.8	427,612	2.76%	356,343	2.30%	71,269	0.46%
Saguaro Units 1-2	06-2014	65 - R2	(20)	16,259,698	13,244,927	6,266,711	11.2	559,528	3.44%	466,273	2.87%	93,255	0.57%
Total Account 314				188,018,474	112,700,899	112,921,270		5,608,177	2.98%	4,673,481	2.49%	934,696	0.50%
Accessory Electric Equipment													
Cholla Unit 1	06-2017	60 - R2.5	(20)	4,756,906	3,592,717	2,115,570	13.9	152,199	3.20%	126,833	2.67%	25,367	0.53%
Cholla Unit 2	06-2033	60 - R2.5	(20)	42,235,818	25,070,631	25,612,111	26.8	955,676	2.26%	796,396	1.89%	159,279	0.38%
Cholla Unit 3	06-2035	60 - R2.5	(20)	29,917,206	18,287,820	19,632,827	28.5	688,871	2.30%	574,059	1.92%	114,812	0.38%
Cholla Common	06-2035	60 - R2.5	(20)	4,476,001	2,380,788	2,990,413	28.7	104,196	2.33%	86,830	1.94%	17,366	0.39%
Four Corners Units 1-3	06-2016	60 - R2.5	(20)	18,353,282	9,525,599	10,098,339	13.2	765,026	4.66%	637,521	3.90%	127,504	0.78%
Four Corners Units 4-5	06-2031	60 - R2.5	(20)	9,183,206	5,039,776	5,980,069	25.9	230,891	2.51%	192,409	2.10%	38,482	0.42%
Four Corners Common	06-2031	60 - R2.5	(20)	2,596,719	2,104,631	1,011,432	21.0	48,163	1.85%	40,136	1.55%	8,027	0.31%
Navajo Units 1-3	06-2026	60 - R2.5	(20)	20,226,194	11,727,970	12,543,463	22.0	570,157	2.82%	475,131	2.35%	95,026	0.47%
Ocotillo Units 1-2	06-2020	60 - R2.5	(20)	2,407,622	2,023,821	865,325	16.3	53,087	2.20%	44,240	1.84%	8,848	0.37%

DECISION NO. 67744

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
Saguaro Units 1-2	06-2014	60 - R2.5	(20)	2,654,661	2,355,021	830,572	11.2	74,156	2.79%	61,799	2.33%	12,360	0.47%
Total Account 315				134,807,415	80,088,776	81,680,122		3,642,425	2.70%	3,035,354	2.25%	607,071	0.45%
316 Miscellaneous Power Plant Equipment													
Cholla Unit 1	06-2017	40 - R2	(20)	2,315,189	1,189,333	1,588,894	13.5	117,696	5.08%	98,080	4.24%	19,616	0.85%
Cholla Unit 2	06-2033	40 - R2	(20)	4,846,431	2,631,492	3,164,225	22.1	144,083	2.97%	120,069	2.48%	24,014	0.50%
Cholla Unit 3	06-2035	40 - R2	(20)	4,138,531	1,990,199	2,976,038	23.8	125,044	3.02%	104,203	2.52%	20,841	0.50%
Cholla Common	06-2035	40 - R2	(20)	7,096,069	2,439,747	6,075,536	25.8	235,486	3.32%	196,238	2.77%	39,248	0.55%
Four Corners Units 1-3	06-2016	40 - R2	(20)	4,330,612	925,502	4,271,232	13.1	326,048	7.53%	271,707	6.27%	54,341	1.25%
Four Corners Units 4-5	06-2031	40 - R2	(20)	3,304,340	1,402,561	2,562,647	23.0	111,419	3.37%	92,850	2.81%	18,570	0.56%
Four Corners Common	06-2031	40 - R2	(20)	8,133,224	3,483,659	6,276,210	23.2	270,526	3.33%	225,439	2.77%	45,086	0.55%
Navajo Units 1-3	06-2026	40 - R2	(20)	11,805,250	5,248,830	8,917,470	20.2	441,459	3.74%	367,882	3.12%	73,576	0.62%
Ocotillo Units 1-2	06-2020	40 - R2	(20)	3,711,192	1,301,603	3,151,827	16.2	194,557	5.24%	162,131	4.37%	32,426	0.87%
Saguaro Units 1-2	06-2014	40 - R2	(20)	3,191,024	1,340,385	2,488,844	10.9	228,334	7.16%	190,279	5.96%	38,056	1.19%
Yucca Unit 1	06-2016	40 - R2	(20)	452,868	359,801	183,841	12.2	15,053	3.32%	12,544	2.77%	2,509	0.55%
Total Account 316				53,324,730	22,313,112	41,676,564		2,209,705	4.14%	1,841,421	3.45%	368,284	0.69%
TOTAL STEAM PRODUCTION PLANT				1,292,132,201	740,269,083	810,289,558		42,761,950		35,634,959		7,126,992	
NUCLEAR PRODUCTION PLANT													
321 Structures and Improvements													
Palo Verde Unit 1	12-2024	65 - R2.5	0	161,039,432	69,557,944	91,481,488	21.2	4,315,165	2.68%	4,315,165	2.68%	0	0.00%
Palo Verde Unit 2	12-2025	65 - R2.5	0	88,415,270	38,859,061	49,556,209	22.0	2,252,555	2.55%	2,252,555	2.55%	0	0.00%
Palo Verde Unit 3	03-2027	65 - R2.5	0	159,591,077	63,133,223	96,457,854	23.3	4,139,822	2.59%	4,139,822	2.59%	0	0.00%
Palo Verde Water Reclamati	03-2027	65 - R2.5	0	125,593,913	51,122,827	74,471,086	23.2	3,209,961	2.56%	3,209,961	2.56%	0	0.00%
Palo Verde Common	03-2027	65 - R2.5	0	98,127,309	39,318,906	58,810,403	23.2	2,534,931	2.58%	2,534,931	2.58%	0	0.00%
Total Account 321				632,767,001	261,989,961	370,777,040		16,452,433	2.60%	16,452,433	2.60%	0	0.00%
322 Reactor Plant Equipment													
Palo Verde Unit 1	12-2024	70 - R1	(2)	359,545,213	153,618,828	213,119,289	20.6	10,345,597	2.88%	10,142,742	2.82%	202,855	0.06%
Palo Verde Unit 2	12-2025	70 - R1	(2)	176,382,235	72,682,559	107,306,921	21.5	4,991,020	2.83%	4,893,156	2.77%	97,863	0.06%
Palo Verde Unit 3	03-2027	70 - R1	(2)	322,750,700	121,218,478	207,987,236	22.6	9,202,975	2.85%	9,022,525	2.80%	180,450	0.06%
Palo Verde Water Reclamati	03-2027	70 - R1	(2)	123,313	7,176	118,803	23.0	5,157	4.18%	5,056	4.10%	101	0.08%
Palo Verde Common	03-2027	70 - R1	(2)	26,449,873	9,583,436	17,395,434	22.6	769,709	2.91%	754,617	2.85%	15,092	0.06%
Total Account 322				885,231,334	357,008,477	545,927,484		25,314,457	2.86%	24,818,095	2.80%	496,362	0.06%
322.1 Reactor Plant Equipment - Steam Generators													
Palo Verde Unit 1	12-2005	Square	(17)	30,722,376	27,569,149	8,376,030	3.0	2,792,010	9.09%	2,386,333	7.77%	405,677	1.32%
Palo Verde Unit 2	12-2003	Square	(17)	15,870,053	15,868,635	2,699,327	1.0	2,699,327	17.01%	2,307,117	14.54%	392,210	2.47%
Palo Verde Unit 3	12-2007	Square	(17)	25,413,317	20,039,935	9,693,646	5.0	1,938,729	7.63%	1,657,033	6.52%	281,696	1.11%
Total Account 322.1				72,005,745	63,477,719	20,769,003		7,430,066	10.32%	6,350,484	8.82%	1,079,582	1.50%
323 Turbogenerator Units													
Palo Verde Unit 1	12-2024	60 - S0	(2)	117,808,078	51,570,896	68,593,344	19.9	3,446,902	2.93%	3,379,315	2.87%	67,586	0.06%
Palo Verde Unit 2	12-2025	60 - S0	(2)	76,754,224	32,432,468	45,856,840	20.8	2,204,656	2.87%	2,161,427	2.82%	43,229	0.06%
Palo Verde Unit 3	03-2027	60 - S0	(2)	142,895,088	55,838,987	89,914,003	21.8	4,124,496	2.89%	4,043,623	2.83%	80,872	0.06%
Palo Verde Water Reclamati	03-2027	60 - S0	(2)	217,707	76,585	145,476	22.0	6,613	3.04%	6,483	2.98%	130	0.06%
Palo Verde Common	03-2027	60 - S0	(2)	1,223,879	346,554	901,803	22.2	40,622	3.32%	39,825	3.25%	797	0.07%
Total Account 323				338,898,976	140,265,490	205,411,466		9,823,287	2.90%	9,630,674	2.84%	192,613	0.06%
324 Accessory Electric Equipment													

DECISION NO. 67744

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

Acct	Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)		Annual Accrual Service Life Amount (11) =	Annual Accrual Service Life Rate (12)=(11)/(5)	Annual Accrual Net Salvage Amount (13) =	Annual Accrual Net Salvage Rate (14)=(13)/(5)
	Palo Verde Unit 1	12-2024	45 - R3	(2)	115,495,170	53,444,066	64,361,007	20.0	3,218,050	2.79%		3,154,951	2.73%	63,099	0.05%
	Palo Verde Unit 2	12-2025	45 - R3	(2)	50,119,388	21,982,186	29,139,590	20.9	1,394,239	2.78%		1,366,901	2.73%	27,338	0.05%
	Palo Verde Unit 3	03-2027	45 - R3	(2)	89,143,623	36,343,481	54,583,014	22.1	2,469,820	2.77%		2,421,392	2.72%	48,428	0.05%
	Palo Verde Common	03-2027	45 - R3	(2)	17,918,193	7,299,463	10,977,094	22.0	498,959	2.78%		489,175	2.73%	9,784	0.05%
	Total Account 324				272,676,374	119,069,196	159,060,705		7,581,068	2.78%		7,432,419	2.73%	148,648	0.05%
325	Miscellaneous Power Plant Equipment														
	Palo Verde Unit 1	12-2024	35 - R0.5	(2)	29,671,405	11,770,905	18,493,928	17.7	1,044,855	3.52%		1,024,367	3.45%	20,487	0.07%
	Palo Verde Unit 2	12-2025	35 - R0.5	(2)	26,389,406	8,702,844	18,214,350	18.7	974,029	3.69%		954,931	3.62%	19,099	0.07%
	Palo Verde Unit 3	03-2027	35 - R0.5	(2)	27,284,046	9,445,478	18,384,249	19.2	957,513	3.51%		938,738	3.44%	18,775	0.07%
	Palo Verde Water Reclamati	03-2027	35 - R0.5	(2)	88,819	27,706	62,889	19.5	3,225	3.63%		3,162	3.56%	63	0.07%
	Palo Verde Common	03-2027	35 - R0.5	(2)	48,459,510	15,382,218	34,046,482	19.4	1,754,973	3.62%		1,720,562	3.55%	34,411	0.07%
	Total Account 325				131,893,186	45,329,151	89,201,899		4,734,595	3.59%		4,641,760	3.52%	92,835	0.07%
	TOTAL NUCLEAR PRODUCTION PLANT				2,333,472,816	987,139,994	1,381,147,596		71,335,907			69,325,866		2,010,041	
	HYDRO PRODUCTION PLANT														
331	Structures and Improvement	12-2004	200-SQ	0	100,878	100,878	0	0.0	0	0.00		0	0.00%	0	0.00%
332	Reservoirs, Dams and Wate	12-2004	200-SQ	0	991,936	1,105,086	(113,150)	0.0	0	0.00		0	0.00%	0	0.00%
333	Water Wheels, Turbines an	12-2004	200-SQ	0	157,196	157,196	0	0.0	0	0.00		0	0.00%	0	0.00%
334	Accessory Electric Equipme	12-2004	200-SQ	0	627,611	627,611	0	0.0	0	0.00		0	0.00%	0	0.00%
335	Miscellaneous Power Plant I	12-2004	200-SQ	0	126,018	126,018	0	0.0	0	0.00		0	0.00%	0	0.00%
336	Roads, Railroads and Bridg	12-2004	200-SQ	0	77,427	77,427	0	0.0	0	0.00		0	0.00%	0	0.00%
	Hydro Decomissioning Costs				-	7,884,531	5,335,469	2.0	2,667,735			2,667,735	100.00%	0	0.00%
	TOTAL HYDRO PRODUCTION PLANT				2,081,066	10,058,747	5,222,319		2,667,735			2,667,735		0	
	OTHER PRODUCTION PLANT														
341	Structures and Improvements														
	Douglas CT	06-2017	80 - S1	(5)	4,582	4,148	642	13.9	46	1.01%		44	0.96%	2	0.05%
	Ocotillo CT 1 - 2	06-2017	80 - S1	(5)	328,749	230,819	114,367	14.5	7,887	2.40%		7,512	2.28%	376	0.11%
	Saguaro CT	06-2017	80 - S1	(5)	1,288,525	466,971	885,980	14.4	61,526	4.77%		58,597	4.55%	2,930	0.23%
	Solar Unit 1		12 - SQ	0	375,512	383,809	(8,297)	3.6	0	0.00%	(2)	0	0.00%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	80 - S1	(5)	510,951	419,492	117,007	14.2	8,240	1.61%		7,848	1.54%	392	0.08%
	West Phoenix Combined Cy	06-2031	80 - S1	(5)	6,706,722	2,438,522	4,603,536	28.1	163,827	2.44%		156,026	2.33%	7,801	0.12%
	Yucca CT 1 - 4	06-2016	80 - S1	(5)	452,751	222,815	252,574	13.4	18,849	4.16%		17,951	3.96%	898	0.20%
	Total Account 341				9,667,772	4,166,576	5,965,809		260,376	2.69%		247,977	2.56%	12,399	0.13%
342	Fuel Holders, Products and Accessories														
	Douglas CT	06-2017	70 - S1	(5)	137,759	100,065	44,582	14.0	3,184	2.31%		3,033	2.20%	152	0.11%
	Ocotillo CT 1 - 2	06-2017	70 - S1	(5)	719,859	517,984	237,868	14.0	16,991	2.36%		16,181	2.25%	809	0.11%
	Saguaro CT	06-2017	70 - S1	(5)	1,304,977	1,019,500	350,726	14.0	25,052	1.92%		23,859	1.83%	1,193	0.09%
	West Phoenix CT 1 - 2	06-2017	70 - S1	(5)	1,437,533	1,123,270	386,140	14.0	27,581	1.92%		26,268	1.83%	1,313	0.09%
	West Phoenix Combined Cy	06-2031	70 - S1	(5)	19,343,993	2,849,135	17,662,058	27.7	637,619	3.30%		607,257	3.14%	30,363	0.16%
	Yucca CT 1 - 4	06-2016	70 - S1	(5)	3,232,217	2,859,228	534,600	12.9	41,442	1.28%		39,468	1.22%	1,973	0.06%
	Total Account 342				26,176,338	8,269,182	19,215,973		751,870	2.87%		716,066	2.74%	35,803	0.14%
343	Prime Movers														
	Douglas CT	06-2017	70 - L1.5	0	1,101,449	999,227	102,222	14.2	7,199	0.65%	(1)	7,199	0.65%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	70 - L1.5	0	6,679,324	5,679,469	999,855	14.1	70,912	1.06%		70,912	1.06%	0	0.00%
	Saguaro CT	06-2017	70 - L1.5	0	8,102,651	6,657,234	1,445,417	13.8	104,740	1.29%		104,740	1.29%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	70 - L1.5	0	8,802,636	6,220,272	2,582,364	14.2	181,857	2.07%		181,857	2.07%	0	0.00%
	Yucca CT 1 - 4	06-2016	70 - L1.5	0	7,920,584	7,302,457	618,127	14.2	43,530	0.55%	(1)	43,530	0.55%	0	0.00%

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ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)	Annual Accrual Service Life Amount (11) =	Annual Accrual Service Life Rate (12)=(11)/(5)	Annual Accrual Net Salvage Amount (13) =	Annual Accrual Net Salvage Rate (14)=(13)/(5)
	Total Account 343				32,806,644	26,858,659	5,747,985		408,237	1.25%	408,237	1.25%	0	0.00%
344	Generators and Devices													
	Douglas CT	06-2017	37 - R3	0	551,765	542,840	8,925	9.7	920	0.17%	920	0.17%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	37 - R3	0	6,402,044	3,500,409	2,901,635	13.6	213,356	3.33%	213,356	3.33%	0	0.00%
	Saguaro CT	06-2017	37 - R3	0	4,185,247	2,504,957	1,680,290	13.0	129,253	3.09%	129,253	3.09%	0	0.00%
	Solar Unit 1		12 - SQ	0	6,933,081	3,289,918	3,643,163	7.8	467,072	6.74%	467,072	6.74%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	37 - R3	0	4,115,901	3,202,560	913,341	12.3	74,255	1.80%	74,255	1.80%	0	0.00%
	West Phoenix Combined Cy	06-2031	37 - R3	(2)	81,920,222	11,983,119	71,575,507	26.2	2,731,890	3.33%	2,731,890	3.33%	0	0.00%
	Yucca CT 1 - 4	06-2016	37 - R3	0	5,395,818	4,370,148	1,025,670	11.6	88,420	1.64%	88,420	1.64%	0	0.00%
	Total Account 344				109,504,078	29,393,951	81,748,531		3,705,166	3.38%	3,705,166	3.38%	0	0.00%
345	Accessory Electric Equipment													
	Douglas CT	06-2017	50 - S2	0	353,277	313,549	39,728	13.1	3,033	0.86%	3,033	0.86%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	50 - S2	0	1,494,636	1,281,843	212,793	13.2	16,121	1.08%	16,121	1.08%	0	0.00%
	Saguaro CT	06-2017	50 - S2	0	1,715,774	1,389,500	326,274	13.4	24,349	1.42%	24,349	1.42%	0	0.00%
	Solar Unit 1		12 - SQ	0	169,527	40,179	129,348	9.9	13,065	7.71%	13,065	7.71%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	50 - S2	0	1,557,744	1,315,426	242,318	13.2	18,357	1.18%	18,357	1.18%	0	0.00%
	West Phoenix Combined Cy	06-2031	50 - S2	0	11,925,645	2,562,942	9,362,703	27.8	336,788	2.82%	336,788	2.82%	0	0.00%
	Yucca CT 1 - 4	06-2016	50 - S2	0	2,166,526	1,817,969	348,557	13.0	26,812	1.24%	26,812	1.24%	0	0.00%
	Total Account 345				19,383,129	8,721,408	10,661,721		438,525	2.26%	438,525	2.26%	0	0.00%
346	Miscellaneous Power Plant Equipment													
	Douglas CT	06-2017	70 - L1	0	40,913	30,160	10,753	13.8	779	1.90%	779	1.90%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	70 - L1	0	553,173	418,696	134,477	14.0	9,606	1.74%	9,606	1.74%	0	0.00%
	Saguaro CT	06-2017	70 - L1	0	790,906	410,357	380,549	14.1	26,989	3.41%	26,989	3.41%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	70 - L1	0	957,431	508,533	448,898	14.1	31,837	3.33%	31,837	3.33%	0	0.00%
	West Phoenix Combined Cy	06-2031	70 - L1	0	2,608,877	895,856	1,713,021	26.6	64,399	2.47%	64,399	2.47%	0	0.00%
	Yucca CT 1 - 4	06-2016	70 - L1	0	427,175	357,633	69,542	13.2	5,268	1.23%	5,268	1.23%	0	0.00%
	Total Account 346				5,378,475	2,621,235	2,757,240		138,878	2.58%	138,878	2.58%	0	0.00%
	TOTAL OTHER PRODUCTION PLANT				202,716,436	80,031,011	126,097,259		5,703,052		5,654,849		48,202	

(1) Staff's reallocation of reserves caused account to have a remaining Net Book Value. APS selected the longest life of other plant in that FERC account to calculate remaining life.
(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

	Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)	Annual Accrual Service Life Amount (11) =	Annual Accrual Service Life Rate (12)=(11)/(5)	Annual Accrual Net Salvage Amount (13) =	Annual Accrual Net Salvage Rate (14)=(13)/(5)
	TRANSMISSION PLANT													
352	Structures and Improvements		50 - R4	(5)	27,818,299	12,484,016	16,515,198	35.2	469,182	1.70%	446,840	1.62%	22,342	0.08%
352.5	Structures and Improvements - SCE 500 KV Line				409,725	424,897	(15,172)		13,316	3.25% (a)	13,316	3.25%	0	0.00%
353	Station Equipment		57 - R1.5	0	428,736,305	130,140,054	298,596,251	45.7	6,538,127	1.52%	6,538,127	1.52%	0	0.00%
353.5	Station Equipment - SCE 500 l				7,747,282	7,349,363	397,919		251,787	3.25% (a)	251,787	3.25%	0	0.00%
354	Towers and Fixtures		60 - R3	(35)	83,464,531	46,097,366	66,579,751	38.3	1,738,375	2.08%	1,287,685	1.54%	450,690	0.54%
354.5	Towers and Fixtures - SCE 50				13,752,584	17,477,965	(3,725,381)		446,959	3.25% (a)	446,959	3.25%	0	0.00%
355	Poles and Fixtures - Wood		48 - R1.5	(35)	91,126,939	27,541,958	95,479,410	38.5	2,479,985	2.72%	1,837,026	2.02%	642,959	0.71%
355.1	Poles and Fixtures - Steel		55 - R3	(15)	83,067,888	22,833,440	72,694,631	45.1	1,611,854	1.94%	1,401,612	1.69%	210,242	0.25%
355.5	Poles and Fixtures - SCE 500				930,308	692,575	237,733		30,235	3.25% (a)	30,235	3.25%	0	0.00%
356	Overhead Conductors and De		55 - R3	(35)	205,771,417	94,269,666	183,521,747	38.5	4,766,799	2.32%	3,530,962	1.72%	1,235,837	0.60%
356.5	Overhead Conductors and Devices - SCE 500 KV Line				22,653,515	28,947,611	(6,294,096)		736,239	3.25% (a)	736,239	3.25%	0	0.00%
357	Underground Conduit		48 - S1.5	(10)	10,444,362	4,087,064	7,401,734	35.7	207,331	1.99%	188,483	1.80%	18,848	0.18%
358	Underground Conductors and		40 - R3	(10)	18,551,254	9,702,854	10,703,525	26.3	406,978	2.19%	369,980	1.99%	36,998	0.20%
	TOTAL TRANSMISSION PLANT				994,274,409	402,048,829	742,093,250		19,897,167		17,079,251		2,617,916	

DECISION NO. 67744

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
	DISTRIBUTION PLANT													
361	Structures and Improvements		45 - R2.5	(10)	25,815,042	10,429,908	17,966,638	33.1	542,799	2.10%	493,453	1.91%	49,345	0.19%
362	Station Equipment		44 - L0.5	0	212,357,577	52,722,295	159,635,282	36.9	4,332,029	2.04%	4,332,029	2.04%	0	0.00%
364	Poles, Towers and Fixtures - \		38 - R0.5	(10)	284,200,711	81,128,434	231,492,348	30.9	7,491,662	2.64%	6,810,602	2.40%	681,060	0.24%
364.1	Poles, Towers and Fixtures - !		50 - R3	(5)	53,919,651	5,601,820	51,013,814	46.6	1,094,717	2.03%	1,042,588	1.93%	52,129	0.10%
365	Overhead Conductors and De		53 - O1	(10)	218,856,780	33,437,453	207,305,005	47.7	4,346,017	1.99%	3,950,924	1.81%	395,092	0.18%
366	Underground Conduit		86 - O1	(5)	425,723,116	26,924,767	420,084,505	82.4	5,098,113	1.20%	4,855,346	1.14%	242,767	0.06%
367	Underground Conductors and		29 - L1	(5)	805,505,783	258,865,205	586,915,867	22.9	25,629,514	3.18%	24,409,061	3.03%	1,220,453	0.15%
368	Line Transformers		36 - R3	(5)	486,837,053	235,537,009	275,641,897	24.6	11,204,955	2.30%	10,671,386	2.19%	533,569	0.11%
369	Services		37 - S2	(10)	242,404,812	91,086,515	175,558,778	27.9	6,292,429	2.60%	5,720,390	2.36%	572,039	0.24%
370	Meters		29 - L0	0	91,330,710	34,836,184	56,494,526	21.8	2,596,256	2.84%	2,596,256	2.84%	0	0.00%
370.1	Electronic Meters		26 - R1.5	0	54,691,249	8,612,961	46,078,288	23.3	1,975,913	3.61%	1,975,913	3.61%	0	0.00%
371	Installations On Customers Pr		50 - O2	(20)	25,335,831	3,863,128	26,539,871	45.0	589,775	2.33%	491,479	1.94%	98,296	0.39%
373	Street Lighting and Signal Sys		35 - R2	(20)	57,185,737	22,716,125	45,906,759	25.9	1,772,462	3.10%	1,477,051	2.58%	295,410	0.52%
	TOTAL DISTRIBUTION PLANT				2,984,164,052	865,761,802	2,300,633,578		72,966,640		68,826,478		4,140,162	
	GENERAL PLANT													
390	Structures and Improvements		39 - R1	(15)	96,667,435	24,085,116	87,082,434	30.7	2,836,561	2.93%	2,466,575	2.55%	369,986	0.38%
391	Office Furniture and Equipmer		20 - SQ	0	19,919,640	11,543,613	8,376,027	10.1	829,310	4.16%	829,310	4.16%	0	0.00%
391.1	Office Furniture and Equipmer		8 - R3	0	38,654,946	15,103,632	23,551,314	5.3	4,418,633	11.43%	4,418,633	11.43%	0	0.00%
391.2	Office Furniture and Equipmer		22 - R4	0	7,652,923	2,932,191	4,720,732	14.8	318,968	4.17%	318,968	4.17%	0	0.00%
393	Stores Equipment		20 - SQ	0	1,227,371	1,235,746	(8,375)	2.8	0	0.00% (2)	0	0.00%	0	0.00%
394	Tools, Shop and Garage Equi		20 - SQ	0	12,673,031	4,673,542	7,999,489	13.7	583,904	4.61%	583,904	4.61%	0	0.00%
395	Laboratory Equipment		20 - L1	0	1,350,583	531,270	819,313	12.0	68,504	5.07%	68,504	5.07%	0	0.00%
397	Communication Equipment		19 - S1.5	0	94,309,691	40,677,647	53,632,044	12.0	4,469,337	4.74%	4,469,337	4.74%	0	0.00%
398	Miscellaneous Equipment		24 - S1.5	0	1,336,404	481,755	854,649	16.6	51,454	3.85%	51,454	3.85%	0	0.00%
	TOTAL GENERAL PLANT				273,792,024	101,264,512	187,027,827		13,576,672		13,206,685		369,986	
	TOTAL DEPRECIABLE PLANT STUDIED				8,082,632,804	3,186,573,978	5,582,511,188		228,709,123		212,395,824		16,313,299	

(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

(a) Assets related to the 500 KV SCE Transmission Line are Depreciated at a rate of 3.25%.

		Original Cost at 12/31/02	Book Accumulated Depreciation
	STEAM PRODUCTION PLANT NOT STUDIED		
311	Structures and Improvements - West Phoenix	0	80,895
312	Boiler Plant Equipment - West Phoenix Units	0	300,097
312	Boiler Plant Equipment - Yucca Unit 1	425,323	441,994
314	Turbogenerator Units - West Phoenix Units 4	0	314,512
314	Turbogenerator Units - Yucca Unit 1	184,916	188,319
315	Accessory Electric Equipment - West Phoeni:	33,968	83,338
315	Accessory Electric Equipment - Yucca Unit 1	182,084	185,435
316	Misc. Power Plant Equipment-West Phoenix L	17,267	0
	TOTAL STEAM PRODUCTION PLANT NOT STUDIED	843,558	1,594,590
	GENERAL PLANT NOT STUDIED		
392	Vehicles	28,410,886	20,605,998
396	Power Operated Equipment	27,947,651	18,603,989
	TOTAL GENERAL PLANT NOT STUDIED	56,358,537	39,209,987
	OTHER PROPERTY NOT STUDIED		
	Intangible Plant		
301	Organization	73,839	

DECISION NO. 67744

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
302 Franchises and Consents				883,584									
303 Miscellaneous Intangible Plant				201,550,375									
Leased Property													
321 Structures and Improvements				1,833,193									
322 Reactor Plant Equipment				9,670,223									
323 Turbogenerator Units				2,705,885									
324 Accessory Electric Equipment				944,788									
325 Miscellaneous Power Plant Equipment				563,135									
361 Structures and Improvements				195,512									
368 Line Transformers				179,394									
371 Installations On Customers Premises				60,386									
390 Structures and Improvements				11,160,324									
397 Communication Equipment				245,938									
TOTAL OTHER PROPERTY NOT STUDIED				229,866,377	120,727,768								
TOTAL DEPRECIABLE PLANT IN SERVICE				8,369,701,276	3,348,106,323								
NONDEPRECIABLE PLANT													
310 Land and Land Rights				3,295,268									
320 Land and Land Rights				3,399,728									
330 Land and Land Rights				84,500									
340 Land and Land Rights				28,192									
350 Land and Land Rights				50,808,274									
360 Land and Land Rights				26,755,119									
389 Land and Land Rights				7,327,436									
TOTAL NONDEPRECIABLE				91,678,517									
TOTAL PLANT IN SERVICE				8,461,379,793									

DECISION NO. 67744

PINNACLE WEST ENERGY CORPORTATION

Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
OTHER PRODUCTION									
341 Structures and Improvements									
West Phoenix CC 4	6-2056	80 - S1	(5)	3,768,898	69,749	3,887,594	49.71	78,205	2.08%
342 Fuel Holders, Products and Accessories									
West Phoenix CC 4	6-2056	70 - S1	(5)	4,135,109	62,598	4,279,266	48.32	88,561	2.14%
343 Prime Movers									
West Phoenix CC 4	6-2056	70 - L1.5	(2)	57,116,985	919,686	57,339,639	46.94	1,221,552	2.14%
344 Generators and Devices									
Redhawk CC Units 1 & 2	6-2057	70 - O4	(3)	546,899,426	13,736,086	549,570,323	34.03	16,149,583	2.95%
West Phoenix CC 4	6-2056	37 - R3	(2)	14,296,553	28,896	14,553,588	35.47	410,307	2.87%
Saguaro CT 3	6-2047	37 - R3	0	37,659,176	75,121	37,584,055	35.49	1,059,004	2.81%
Total Account 344				598,855,155	13,840,103	601,707,966		17,618,894	2.94%
TOTAL OTHER PRODUCTION PLANT				**663,876,147**	**14,892,136**	**667,214,465**		**19,007,213**	
TRANSMISSION									
353 Station Equipment									
Redhawk CC Units 1 & 2		57 - R1.5	0	46,000,000	569,193	45,430,807	56.59	802,806	1.75%
West Phoenix CC 4		57 - R1.5	0	1,953,105	72,502	1,880,603	55.77	33,721	1.73%
Total Account 353				47,953,105	641,695	47,311,410		836,527	1.74%
355 Poles and Fixtures- Steel									
Redhawk CC Units 1 & 2 .		55 - R3	(15)	1,500,000	23,458	1,701,542	54.50	31,221	2.08%
356 Overhead Conductors and Devices									
Redhawk CC Units 1 & 2		55 - R3	(35)	1,500,000	23,458	2,001,542	54.50	36,726	2.45%
TOTAL TRANSMISSION PLANT				**50,953,105**	**688,611**	**51,014,494**		**904,473**	
Depreciate Property Totals				**714,829,252**	**15,580,747**	**718,228,959**		**19,911,686**	
NONDEPRECIABLE PLANT									
340 Land									
Redhawk CC Common				2,246,597					
West Phoenix CC 4				32,909	70				
TOTAL NONDEPRECIABLE PLANT				**2,279,507**	**70**				
TOTAL PWE PLANT IN SERVICE				717,108,759	15,580,817				

DECISION NO. 67744

PINNACLE WEST ENERGY CORPORATION

Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

The Calculated Annual Accrual (9) is made up of two depreciation components - service life and net salvage

Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) = (9) * 100/100+(-4))	(12)=(11)/(5)	(13) = (9) * (-4)/100+(-4))	(14)=(13)/(5)
OTHER PRODUCTION													
341 Structures and Improvements													
West Phoenix CC 4	6-2056	80 - S1	(5)	$3,768,898	$69,749	$3,887,594	49.71	$78,205	2.08%	$74,481	1.98%	$3,724	0.10%
342 Fuel Holders, Products and Accessories													
West Phoenix CC 4	6-2056	70 - S1	(5)	4,135,109	62,598	4,279,266	48.32	88,561	2.14%	$84,344	2.04%	$4,217	0.10%
343 Prime Movers													
West Phoenix CC 4	6-2056	70 - L1.5	(2)	57,116,985	919,886	57,339,639	46.94	1,221,552	2.14%	$1,197,600	2.10%	$23,952	0.04%
344 Generators and Devices													
Redhawk CC Units 1 & 2	6-2057	70 - O4	(3)	546,899,428	13,736,086	549,570,323	34.03	16,149,583	2.95%	$15,679,207	2.87%	$470,376	0.09%
West Phoenix CC 4	6-2056	37 - R3	(2)	14,296,553	28,896	14,553,588	35.47	410,307	2.87%	$402,262	2.81%	$8,045	0.06%
Saguaro CT 3	6-2047	37 - R3	0	37,659,176	75,121	37,584,055	35.49	1,059,004	2.81%	$1,059,004	2.81%	$0	0.00%
Total Account 344				598,855,155	13,840,103	601,707,966		17,618,894	2.94%	$17,140,473	2.86%	$478,421	0.08%
TOTAL OTHER PRODUCTION PLANT				663,876,147	14,892,136	667,214,465		19,007,213		18,496,898		510,315	
TRANSMISSION													
353 Station Equipment													
Redhawk CC Units 1 & 2		57 - R1.5	0	46,000,000	569,193	45,430,807	56.59	802,806	1.75%	$802,806	1.75%	$0	0.00%
West Phoenix CC 4		57 - R1.5	0	1,953,105	72,502	1,880,603	55.77	33,721	1.73%	$33,721	1.73%	$0	0.00%
Total Account 353				47,953,105	641,695	47,311,410		836,527	1.74%	$836,527	1.74%	$0	
355 Poles and Fixtures- Steel													
Redhawk CC Units 1 & 2		55 - R3	(15)	1,500,000	23,458	1,701,542	54.50	31,221	2.08%	$27,149	1.81%	$4,072	0.27%
356 Overhead Conductors and Devices													
Redhawk CC Units 1 & 2		55 - R3	(35)	1,500,000	23,458	2,001,542	54.50	36,728	2.45%	$27,204	1.81%	$9,521	0.63%
TOTAL TRANSMISSION PLANT				50,953,105	688,611	51,014,494		904,473		890,880		13,594	
Depreciable Property Totals				$714,829,252	$15,580,747	$718,228,959		$19,911,686		$19,387,778		$523,908	
NONDEPRECIABLE PLANT													
340 Land													
Redhawk CC Common				2,246,597									
West Phoenix CC 4				32,909	70								
TOTAL NONDEPRECIABLE PLANT				2,279,507	70								
TOTAL PWE PLANT IN SERVICE				$717,108,759	$15,580,817								

67744

DECISION NO. ______

Preliminary Energy Efficiency DSM Plan
Arizona Public Service Company

Programs Organized by Market or Customer Segment	Program Descriptions: Elements/Concepts/Strategies/Tactics	Budget [1] (millions)
C&I New Construction	• Energy efficient schools • New construction, renovation, remodeling, equipment replacement • Early project identification • Design assistance • Education and training for designers • High efficiency HVAC, lighting and lighting design, motors/drives, systems and processes, cool roofs/materials (prescriptive and custom measures) • Commissioning[2] • Promotion of high performance buildings, including LEED certification • Building code support	$2.7
C&I Retrofit of Existing Facilities	• Energy efficient schools retrofit, including financial incentives • Large/medium C&I customers • High efficiency HVAC, lighting, motors/drives, O&M, systems and processes, cool roofs/materials (prescriptive and custom measures) • Building operator training and certification • Retro-commissioning[3] • Vendor and contractor training • National accounts/franchises • Municipal financial incentives • Education and information	$2.5
Small Business	• Lighting, HVAC, refrigeration • Technical assistance • Vendors market directly to customers in a one-stop, turnkey approach • Financial incentives	$1.7
C&I Subtotal		$6.9

[1] Includes incremental labor
[2] Commissioning uses a systematic process to optimize a new building's operations, and to ensure that new buildings operate and perform as intended by their designers, supported with documentation and training.
[3] Retro-commissioning uses a systematic process to improve and optimize an existing building's operations and to support those improvements with enhanced documentation and training.

DECISION NO. 67744

DOCKET NO. E-01345A-03-0437

Preliminary Energy Efficiency DSM Plan
Arizona Public Service Company

Programs Organized by Market or Customer Segment	Program Descriptions: Elements/Concepts/Strategies/Tactics	Budget (millions)
Residential New Construction	• Energy Star Plus equivalent (high performance) homes for leading builders • Energy Star equivalent promotion for the mainstream builders • Builder/contractor/realtor training • Guaranteed heating/cooling • Home performance testing • Lighting and appliances packages • Building code support	$2.4
Residential Existing Homes and HVAC	• HVAC contractor training and certification, systems approach • High efficiency HVAC systems • Duct testing and sealing • Home performance testing • Other cost-effective measures, including insulation and trees • Consumer education	$1.4
Residential Consumer Products	• Energy Star consumer products (lighting, appliances, windows) • Point of purchase displays/education • Cooperative advertising/marketing • Industry partnerships and buy downs • Retailing training • Federal efficiency standards support	$1.4
Residential Low Income	• Expand existing low income weatherization program • Lighting and appliance measures • Bill assistance	$1.0
Residential Subtotal		**$6.2**

Preliminary Energy Efficiency DSM Plan
Arizona Public Service Company

Programs Organized by Market or Customer Segment	Program Description: Elements/Concepts/Strategies/Tactics	Budget (millions)
Residential and C&I Programs Subtotal		$13.1
Measurement, Evaluation, and Research	MER plan will be developed for each DSM program. As a general rule, MER costs should be about 3% to 8% of total DSM budget. MER budget includes funding for some baseline studies to determine current practices, stock, and efficiency levels.	$1.3
Performance Incentive	Share (%) of DSM net economic benefits (benefits minus costs), capped at 10% of total DSM expenditures, inclusive of the performance incentive.	$1.6
TOTAL		$16.0

APPENDIX C

SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

1.4 Company will supply electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to Company's distribution system.

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and sign Company's standard form of application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the customer shall be deemed to constitute a service agreement by and between Company and the customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.

2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.

2.2 Service Establishment Charge - A service establishment charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the customer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month. Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill.

The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.

2.2.1 The customer may additionally be required to pay a trip charge of $16.00 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to meter panel.

2.2.2 The customer may additionally be required to pay an after-hour charge of $75.00 should the customer request service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established during a period other than regular working hours, or on the same day of their request, regardless of the time the order may be worked by Company.

2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be $75.00 per hour.

2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.6 hereof.

2.4.4 The applicant is known to be in violation of Company's tariff.

2.4.5 The applicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the applicant and which have been specified by Company as a condition for providing service.

2.4.6 The applicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the applicant is requesting service.

2.4.8 Service is requested by an applicant and a prior customer living with the applicant owes a delinquent bill.

2.4.9 The applicant is acting as an agent for a prior customer who is deriving benefits of the service and who owes a delinquent bill.

2.4.10 The applicant has failed to obtain all required permits and/or inspections indicating that the applicant's facilities comply with local construction and safety codes.

2.5 Establishment of Credit or Security Deposit

2.5.1 Residential Establishment of Credit - Company shall not require a security deposit from a new applicant for residential service if the applicant is able to meet any of the following requirements:

2.5.1.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company.

2.5.1.3 The applicant can produce a letter regarding credit or verification from an electric utility where service of a comparable nature was last received which states that the applicant had a timely payment history at the time of service discontinuation.

2.5.1.4 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.2 Residential Establishment of Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the applicant left an unpaid final bill owing to another utility company, the applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Nonresidential Establishment of Security Deposit - All nonresidential customers may be required to:

2.5.3.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.3.2 Provide a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Nonresidential - Company may require a nonresidential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a six (6) consecutive month period or if the customer has been disconnected for non-payment during the last twelve (12) months, or when the customer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all customers of the Arizona Corporation Commission's complaint process should the customer dispute the deposit based on the financial data.

2.7 Security Deposits

2.7.1 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by the Company:

2.7.1.1 If the customer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or,

2.7.1.2 If the customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,

2.7.1.3 If the customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that APS is providing bundled electric service.

2.7.2 Separate security deposits may be required for each service location.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of customer obligation under the agreement for service.

2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.

2.7.5 If the customer terminates all service with Company, the security deposit may be credited to the customer's final bill.

2.7.6 Residential security deposits shall not exceed two (2) times the customer's average monthly bill as estimated by Company for the services being provided by the Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the customer has not been delinquent more than twice, unless Customer has filed bankruptcy in the last 12 months.

2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the customer's maximum monthly billing as estimated by Company for the service being provided by the Company.

2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

3 Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that customer for the requested type of service. In addition, Company shall notify its customers of any changes in Company tariffs affecting those customers.

3.2 Rate Selection – The customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the customer is being served on a Standard Offer rate, Company will use reasonable care in initially establishing service to the customer under the most advantageous Standard Offer rate schedule applicable to the customer. However, because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the customer would have paid less for service had the customer been billed on an alternate applicable rate or provision of that rate.

3.3 Standard Offer Optional Rates – Certain optional Standard Offer rate schedules applicable to certain classes of service allow the customer the option to select the rate schedule to be effective initially or after service has been established. A customer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company. Billing under the alternate rate will become effective from the next meter reading, or when the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the customer is provided service specifies a term, the customer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access rate selection will be effective upon the next meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service.

3.5 Any customer making a Direct Access rate selection may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access for the succeeding twelve (12) month period. If a customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer.

4 Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 Company normally meters and bills each site separately; however, adjacent and contiguous sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business, will be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The customer's service installation will normally be arranged to accept only one type of service at one point of delivery to enable service measurement through one meter. If the customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by Company are due and payable no later than fifteen (15) days from the billing date. Any payment not received within this time frame shall be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the customer's service for non-payment of any Arizona Corporation Commission approved services. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C. R 14-2-201.9, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the customer for the same class of service. The failure of the customer to pay the active account shall result in the suspension or termination of service thereunder.

4.2.3 Unpaid charges incurred prior to the customer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until the Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the customer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. Any refunds to customers resulting from overbillings will be made promptly upon discovery by Company. Underbillings by Company shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.

4.3.3 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of up to $10.00 per customer to customers who elect to pay their bills using Company's electronically transmitted payment options.

4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of $5.00 per customer for a customer electing to forego the presentation of a paper bill.

4.4 Dishonored Payments - If Company is notified by the customer's financial institution that they will not honor a payment tendered by the customer for payment of any bill, Company may require the customer to make payment in cash, by money order, certified check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer shall be charged a fee of $15.00 for each instance where the customer tenders payment of a bill with a payment that is not honored by the customer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Field Call Charge - Company may require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the customer's site to accept payment of a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

4.5.1 If a termination is required at the pole, a reconnection charge of $96.50 will be required; if the termination is in underground equipment, the reconnection charge will be $115.00.

4.5.2 To avoid termination of service, the customer may make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company may require payment of an On-site Evaluation Charge of $82.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of if the customer actually implements Company suggestions.

5 Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the customer's side of the point of delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the customer under hazardous conditions.

5.2.2 The customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the customer's site for the purpose of supplying service to the customer.

5.2.3 The customer shall be responsible for payment for loss or damage to Company property on the customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.

5.2.5 The customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the customer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites - Company's authorized agents shall have unassisted access to the customer's sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any existing rate options where access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored. Written termination notice is required prior to disconnecting service under this schedule.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of the extension which is on sites owned, leased or otherwise controlled by the customer shall be furnished in Company's name by the customer without cost to Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense. Company will notify the customer in writing of the violations.

5.6 Load Characteristics – The customer shall exercise reasonable care to assure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. The deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. In situations where Company suspects that a customer's load has a non-conforming power factor, Company may install at its cost the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a power factor of less than 90%, or leading, or other detrimental conditions shall be required to remedy problems in order to achieve a power factor in conformance with above standards, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem, kVa may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

6. Metering and Metering Equipment

6.1 Customer Equipment - The customer shall install and maintain all wiring and equipment beyond the point of delivery. Except for Company's meters and special equipment, the customer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish an inspection or permit if required by law or by Company.

6.1.1 The customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.

6.1.2 If telephone lines or any other devices are required to read the customer's meter, the customer is responsible for the installation, maintenance, and usage fees at no cost to Company.

6.1.3 Where a customer requests, and Company approves, a special meter reading device to accommodate the customer's needs, the cost for such additional equipment shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will be charged the replacement costs less five (5) years depreciation plus an administration fee of fifteen percent (15%).

6.2.2 Company will lease lock ring keys to MSP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the MSP and/or its authorized agents are:

1) No longer permitted to remove Company meters pursuant to conditions of the Company's Schedule 10;
2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the MSP, the customer, and/or its' agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $62.00 per site. Company may assess an additional charge of $53.00 per hour for joint site meetings that exceed thirty (30) minutes. In the event Company must temporarily replace the MSP's meter and/or associated metering equipment as necessary during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider. For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors. For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry credentials which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the customer will be measured by commercially acceptable measuring devices by Company or the Meter Reading Service Provider (MRSP) pursuant to the terms and conditions of Company's Schedule 10. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer customers, or where Company is the MRSP, the readings of the meter will be conclusive as to the amount of electric power supplied to the customer unless there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the customer will be billed for the estimated energy consumption that would have registered had all energy usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer may also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the MRSP.

6.4.4 Customer will be billed for the estimated energy and demand that would have registered had the meter been operating properly. Where Company is the MRSP, Company shall, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is $16.50 and may be charged to the customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the MSP or MRSP, and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may obtain the data, or may estimate the billing determinants. The charge for such reread is $16.50 and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon customer or ESP request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the customer or the ESP $30.00 for the meter test if the meter is removed from the site and tested in the meter shop, and $50.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes, Condominiums and Other Multiunit Residential Buildings - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A customer violation of any of the applicable rules of the Arizona Corporation Commission or Company tariffs.

7.1.2 Failure of the customer to pay a delinquent bill for services provided by Company.

7.1.3 The customer's breach of a written contract for service.

7.1.4 Failure of the customer to comply with Company's deposit requirements.

7.1.5 Failure of the customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any customer without advance notice under any of the following conditions:

7.2.1 The existence of an obvious hazard to the health or safety of persons or property.

7.2.2 Company has evidence of meter tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8 Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the customer, and Company shall be under no further obligation to serve the customer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the customer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same customer at the same location.

For purposes of this Section notice to the customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the customer at his/her last known address.

9 Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the customer and Company, but no assignments by the customer shall be effective until the customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

APPENDIX D SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or upgrades to existing facilities. Costs for construction depend on the customer's location, load size, and load characteristics. This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. Construction allowance and revenue basis methodologies are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within the construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and company facilities at the beginning point of an extension also as determined by Company.

The following policy governs the extension of overhead and underground electric facilities, and underground facilities as specified in Section 6, to customers whose requirements are deemed by Company to be usual and reasonable in nature.

1. FOOTAGE BASIS - RESIDENTIAL ONLY

1.1 GENERAL POLICY - Footage basis extensions may be made only if all of the following conditions exist:

1.1.1 The applicant is a new permanent residential customer or group of new permanent residential customers. Customers specified in Section 4 below are not eligible for this allowance.

1.1.2 The total extension does not exceed 2,000 feet per customer and under no circumstances can the total allowable distance exceed 10,000 feet.

1.1.3 The total extension does not exceed a total construction cost of $25,000.

1.1.4 No construction allowance will be permitted beyond the shortest practical route to the nearest practical point of delivery on each customer's site as determined by Company.

1.2 FREE EXTENSIONS - May be made if the conditions specified in Section 1.1 are met and:

1.2.1 The free extension will be limited to a maximum of 1,000 feet per new permanent residential customer.

1.2.2 Free allowance for the total extension will be 1,000 feet per customer regardless of the customer's location along the route of the extension.

1.3 EXTENSIONS OVER THE FREE DISTANCE

For extensions which meet the conditions specified in Section 1.1 above, and which exceed the free distance specified in Section 1.2.1, Company may extend its facilities up to the maximum allowed in Section 1.1.2 provided the customer or customers will sign an extension agreement and advance the cost of such additional footage. Advances are subject to refund as specified in Section 5.

SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

2. REVENUE BASIS - NON-RESIDENTIAL

2.1 GENERAL POLICY - Revenue basis extensions may be made only if all of the following conditions exist:

2.1.1 Applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

2.1.2 Such extension does not exceed a total construction cost of $25,000.

2.2 FREE EXTENSIONS

Such extension shall be free to the customer where the conditions specified in Section 2.1 herein are met and the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable customer contributions.

2.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 2.1, above, and which exceed the free limits specified in Section 2.1.2, Company may extend its facilities up to a cost limitation of $25,000, provided the customer or customers will sign an extension agreement and advance a sufficient portion of the construction cost so that the remainder satisfies the requirements of Section 2.2. Advances are subject to refund as specified in Section 5.

3. ECONOMIC FEASIBILITY BASIS

3.1 GENERAL POLICY - Extensions may be made on the basis of economic feasibility only if all of the following conditions exist:

3.1.1 The applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

3.1.2 The total construction cost exceeds $25,000 except for extensions specified in Sections 4.4 or 7.7.

3.2 FREE EXTENSIONS

Such extensions shall be free to the customer where the conditions specified in Section 3.1 are met and the extension is determined to be economically feasible. "Economic feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer.

3.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 3.1, above, Company, after special study and at its option, may extend its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 3.2, provided such customers sign an extension agreement and advance as much of the construction cost and/or agree to pay such higher special rate (facilities charge) as is required to make the extension economically feasible. Advances are subject to refund as specified in Section 5.

4. OTHER CONDITIONS

4.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost. Advances are subject to refund as specified in Section 5.2. Non-agricultural irrigation pumping will be extended as specified in Section 2 or 3.

4.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the customer, then the customer, in advance of installation or construction, shall make a non-refundable contribution equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

4.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the customer's residence or operation is doubtful, the customer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 5.3.

4.4 REAL ESTATE DEVELOPMENT

Extensions of electric facilities within real estate developments including residential sub divisions, industrial parks, mobile home parks, apartment complexes, planned area developments, etc., may be made in advance of application for service by permanent customers, as specified in Section 3. Anticipated revenue for Residential Real Estate extensions shall be calculated from information provided by the developer.

4.4.1 MOBILE HOME PARKS - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by the utility.

4.4.2 RESIDENTIAL APARTMENT COMPLEXES, CONDOMINIUMS AND OTHER MULTI UNIT RESIDENTIAL BUILDINGS - Company shall refuse service to all new construction and/or expansion of apartment complexes and condominiums unless the construction and/or expansion is individually metered by the utility. Master metering will only be allowed for buildings utilizing centralized heating, ventilation and/or air conditioning system where the contractor can provide an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations.

5. REFUNDS

5.1 REVENUE AND ECONOMIC FEASIBILITY BASIS REFUNDS

5.1.1 Customer advances over $50.00 are subject to full or partial refund, provided that a survey based on conditions of the extension, not including laterals or extensions from the extension being surveyed as specified in Section 5.1.2 existing at the time of survey, results in an advance lower than the amount actually advanced. Except as provided for in Section 5.3, such surveys shall not be made for customers extended to under the basis specified in Section 4.1, 4.2, or 4.3. A survey will be conducted by Company five (5) years after signing the extension agreement under the extension policy in force at the time of the extension . Upon request, the customer will be entitled to intermediate surveys within the five (5) year period after the end of six (6) months following the date of signing the extension agreement and subsequent surveys at intervals of not less than one (1) year thereafter. Company will refund the difference between the amount advanced and the amount that would have been advanced had the advance been calculated at the time of survey. In no event shall the amount of any refund exceed the amount originally advanced.

5.1.2 Laterals or extensions from an extension being surveyed shall not be considered in the survey when the lateral or extension was extended on the basis "extensions over the free limits" of Sections 2.2 or 3.2, or is not connected directly to the extension being surveyed. In real estate developments extended to under the basis specified in Section 4.4, the survey may include laterals and extensions to serve permanent customers located within the real estate development described in the extension agreement for the extension being surveyed.

5.1.3 In lieu of surveys, Company will determine the refund based on the number of permanent connections to the extension for residential real estate development. In such event, Company shall specify in the extension agreement the amount of refund per permanent customer connection.

5.2 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

Customer advances over $50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.3 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances over $50.00 are subject to full or partial refund pursuant to surveys based on the Revenue or Economic Feasibility Basis as specified in Section 5.1.1. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the customer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.4. GENERAL REFUND CONDITIONS

5.4.1 Customer advances of $50.00 or less are not subject to refund.

5.4.2 No refund will be made to any customer for an amount more than the unrefunded balance of the customer's advance.

5.4.3 Any unrefunded balance of the customer's advance shall become nonrefundable five (5) years from the date of Company's receipt of the advance.

5.4.4 Company reserves the right to withhold refunds to any customer whose account is delinquent and apply these refund amounts to past due bills.

6. UNDERGROUND CONSTRUCTION

6.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

6.1.1 The extension meets feasibility requirements as specified in Sections 1, 2, 3, or 4.

6.1.2 The customer or developer provides all earthwork including, but not limited to, trench, boring or punching, conduits, backfill, compaction, and surface restoration in accordance with Company specifications.

(Company may provide all earthwork and the customer or developer will make a nonrefundable contribution equal to the cost of such work provided by Company.)

6.2 THREE-PHASE UNDERGROUND CONSTRUCTION - Where it is determined that three phase is required to serve the customer, Company may install three-phase facilities if the conditions specified in Section 6.1 are met, and the customer provides the following:

6.2.1 Installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications. In lieu of providing conduits, the customer may provide a nonrefundable contribution equal to the estimated difference in cost between overhead and underground facilities.

6.2.2 A nonrefundable contribution for excess service footage required by the customer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.

6.2.3 Transformer pad and secondary conduits in accordance with Company specifications. (Company may provide pad and conduits, and the customer or developer will make a non-refundable contribution equal to the cost of such work provided by Company.)

7. GENERAL CONDITIONS

7.1 VOLTAGE

The extension will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located.

7.2 THREE PHASE

Extensions for three phase service can be made under this extension policy where the customer has installed major three phase equipment. Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total horsepower of all connected three phase motors exceeds 12 HP or total load exceeding 100 kVa demand shall qualify for three phase. If the estimated load is less than the above horsepower or connected kVa specifications, Company may, at its option and when requested by the customer, serve three phase and require a nonrefundable contribution equal to the difference in cost between single phase and three phase construction, but in no case less than $100.

7.3 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

7.4 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by Customer or developer.

7.5 OWNERSHIP

Except for customer-owned facilities, all construction, including that for which customers have made advances and/or contributions, will be owned, operated and maintained by Company.

7.6 MEASUREMENT AND LOCATION

7.6.1 Measurement must be along the proposed route of construction.

7.6.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

7.6.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

7.7 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when Customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

7.8 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way nonstandard, as determined by Company, or if unusual obstructions are encountered, the customer will make a non- refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

7.9 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided the customer makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

7.10 RELOCATIONS AND/OR CONVERSIONS

7.10.1 Company will relocate or convert its facilities for the customer's convenience or aesthetics, providing the customer makes a nonrefundable contribution equal to the total cost of relocation or conversion.

7.10.2 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for the customer's convenience or aesthetics, then the relocation or conversion costs plus the costs to serve will be used to determine the customers advance on the basis specified in Section 2 or 3.

7.11 CHANGING OF MASTER METER TO INDIVIDUAL METER

Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on basis specified in Section 2 or 3.

7.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the customer's added load or change in service requirements on the basis specified in Section 2 or 3.

7.13 DESIGN DEPOSIT

Any applicant requesting Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction; otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the customer for a line extension upon request.

7.14 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

7.15 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

7.16 INTEREST

All advances made by the customer to Company in aid of construction shall be non-interest bearing.

7.16 EXTENSION AGREEMENTS

All line extensions requiring payment by the customer shall be in writing and signed by both the customer and Company.

7.17 ADDITIONAL PRIMARY FEED

Company will provide an additional primary (alternate) feed as requested by the customer provided the customer pays the added cost for the additional feed as a nonrefundable contribution in aid of construction and pays the applicable rate for the additional feed requested.

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APPENDIX E

SCHEDULE 7

ELECTRIC METER TESTING AND MAINTENANCE PLAN

General Plan

This schedule establishes a meter maintenance and testing program for electric meters in order to ensure an acceptable degree of performance in the registration of the energy consumption of Arizona Public Service Company (Company) customers. Company will file an annual report with the Arizona Corporation Commission summarizing the results of the meter maintenance and testing program.

Specific Plan

1. Single-Phase Self Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

1.1 Meters shall be separated into groups having common physical attributes and the average performance of each group will be determined based on the weighted average of the meter's percentage registration at light load (LL) and at full load (FL) giving the full load registration a weight factor of four (4).

1.2 Analysis of the test results for each group evaluated shall be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 – 1995 Formulas B-3, Tables A-1, A-2 and B-5. The minimum sample size shall be 100 meters when possible.

2. Single Phase Self Contained Meters – Solid State

Company will monitor performance of these types of meters through the Company Metering and Billing systems.

3. Three Phase Self-Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

Company shall monitor installations with the following types of meters for accuracy and recalibrate as necessary according to the following schedule:

3.1 Three-phase meters with surge-proof magnets and without demand registers or pulse initiators: 16 years.

3.2 Three phase block-interval demand-register-equipped kWh meters with surge-proof magnets: 12 years.

3.3 Three phase lagged-demand meters: 8 years.

4. Three Phase Self-Contained Meters – Solid State

Company will monitor performance for these types of meters through the Company Metering and Billing systems.

5. Three Phase Transformer-Rated Meter Installations – Solid State Hybrids and Electro-Mechanical

Company will conduct a periodic testing program whereby three phase transformer-rated meter installations along with their associated equipment shall be inspected and tested for accuracy according to the following schedule:

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SCHEDULE 7
ELECTRIC METER TESTING AND MAINTENANCE PLAN

5.1 Installations with 500 to 1,000 kW load: 4 years.

5.2 Installations with 1001 kW to 2000 kW load: 2 years.

5.3 Installations over 2000 kW load: 1 year.

APPENDIX F

SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

The following terms and conditions and any changes authorized by law will apply to Arizona Public Service Company (Company), Energy Service Providers (ESPs), and their agents that participate in Direct Access under the Arizona Corporation Commission's (ACC) rules for retail electric competition (A.A.C. R14-2-1601, et seq., referred to herein as the "Rules"). "Direct Access customer" refers to any Company retail customer electing to procure its electricity and any other ACC authorized Competitive Services directly from ESPs as defined in the Rules.

Customer Selections

All Company retail customers shall obtain service under one of two options:

1. Standard Offer Service. With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services, at regulated rates authorized by the ACC. Any customer who is eligible for Direct Access who does not elect to procure Competitive Services shall remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access.

2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have Interval Metering, as specified in Section 3.6.1. Pursuant to the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/or Billing Services on their own behalf (or through a qualified third party), or to have Company provide those services (when permitted by the Rules) as specified within.

1. General Terms

1.1. Definitions. The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.

1.1.1 Customer - Unless otherwise stated, all references to Customer in this agreement refer to Company customers who are eligible for and have elected Direct Access.

1.1.2. Service Account - Unless otherwise stated, all references to "Service Account" in this agreement shall refer to an installed service, identified by a Universal Node Identifier (UNI).

1.1.3 Local Arizona Time – All time references in this Schedule are in Local Arizona Time, which is Mountain Standard Time (MST).

2. General Obligations of Company

2.1. Non-Discrimination

2.1.1. Company shall discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission ("FERC") or applicable affiliate transactions rules, Company shall not:

2.1.1.1. Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of Company services than other, unaffiliated services providers as a result of affiliation with Company; or

2.1.1.2. Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of Company services.

2.2. Transmission and Distribution Service

Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.

3. General Obligations of ESPs

3.1. Timeliness, Due Diligence and Security Requirements

3.1.1 ESPs shall exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs shall make all payments owed to Company in a timely manner.

3.1.2. ESPs shall adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and Company tariffs and schedules.

3.2. Arrangements with ESP Customers

ESPs shall be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access. Company shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3.3. Responsibility for Electric Purchases

ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

3.4. Company Not Liable for ESP Services

To the extent the customer elects to procure services from an ESP, Company has no obligations to the customer with respect to the services provided by the ESP.

3.5. Load Aggregation for Procuring Electric Generation/Split Loads

3.5.1. ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation shall not be used to compute Company charges or for tariff applicability.

3.5.2. Customers requesting Direct Access Services may not partition the electric loads of a Service Account among electric service options or providers. The entire load of a Service Account must be provided by only one (1) ESP. This provision shall not restrict the use of separate parties for metering and billing services.

3.6 Interval Metering

3.6.1. "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and reach a single site maximum demand in excess of 20 kW one or more times or annual usage of 100,000 kWh or more. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less or annual usage of less than 100,000 kWh.

3.6.2. Company shall determine if Customer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers.

3.7. Meter Data Requirements

Minimum meter data requirements consist of data required to bill Company distribution tariffs and determine transmission settlement. Company shall have access to meter data necessary for regulatory purposes or rate-setting purposes pursuant to mutually agreed upon terms with the ESP for such data access.

3.8. Statistical Load Profiles

Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9 Fees and Other Charges

Direct Access customers shall pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.

3.10 Liability In Connection With ESP Services

3.10.1. "Damages" shall include all losses, harm, costs and detriment, both direct and indirect, and consequential, suffered by Customer or third parties.

3.10.2. Company shall not be liable for any damages caused by Company conduct in compliance with, or as permitted by, Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service, or as otherwise set forth in Company's Schedule #1.

3.10.3. Company shall not be liable for any damages caused to Customer by any ESP, including failure to comply with Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.

3.10.4. Company shall not be liable for any damages caused by the ESP's failure to perform any commitment to Customer.

3.10.5. An ESP is not a Company agent for any purpose. Company shall not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.

3.10.6 Under no circumstances shall Company be liable to Customer, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision shall not limit remedies otherwise available to customers under Company's schedules and tariffs and applicable laws and regulations.

4. Customer Inquiries and Data Accessibility

4.1 Customer Inquiries – For customers requesting information on Direct Access, Company shall make available the following information:

4.1.1 Materials to consumers about competition and consumer choices.

4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within Company's service territory. Company will provide the list maintained by the ACC, but Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list shall not be considered an endorsement or other form of recommendation by Company.

4.2. Access to Customer Usage Data. For Company customers on Standard Offer Service, Company shall provide customer specific usage data to ESP or to Customer, subject to the following provisions:

4.2.1. ESPs may request Customer usage data prior to submission of a Direct Access Service Request ("DASR") by obtaining and submitting to Company the Customer's written authorization on a Customer Information Service Request ("CISR") form. Company may charge for customer usage data at rates approved by the ACC.

4.2.2. Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage history.

4.3 Customer Inquires Concerning Billing Related Issues

4.3.1 Customer inquiries concerning Company charges or services shall be directed to Company.

4.3.2 Customer inquiries concerning ESP charges or services shall be directed to the ESP.

4.4 Customer Inquiries Related to Emergency Situations and Outages

4.4.1. Company shall be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to Company for resolution. ESPs performing consolidated billing must show Company's emergency telephone number on their bills.

4.4.2. Company may shed or curtail customer load as provided by its ACC-approved tariffs and schedules, or by other ACC rules and regulations.

5. ESP Service Establishment

5.1 Before the ESP or its agents can offer Direct Access services in Company's distribution service territory they must meet the applicable provisions as listed:

5.1.1 All ESPs must obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services in Company's distribution service territory.

5.1.2 All ESPs must register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services in Company's distribution service territory.

5.1.3. Load Serving ESPs must satisfy creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.

5.1.4 Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.

5.1.5. All ESPs must satisfy any applicable ACC electronic data exchange requirements including:

5.1.5.1. The ESP and/or its designated agents must complete to Company's satisfaction all necessary electronic interfaces between the ESP and Company to exchange DASRs and general communications.

5.1.5.2. The ESP or its agent must complete to Company's satisfaction all electronic interfaces between the ESP and Company to exchange meter reading and usage data. This includes communication to and from the Meter Reading Service Provider's (MRSP) server for sharing of meter reading and usage data.

5.1.5.3. The ESP must have the capability to electronically exchange data with Company. Alternative arrangements may be acceptable at Company's option.

5.1.5.4. The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when providing meter reading services. Alternative arrangements may be allowed at Company's option.

5.1.6 For Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing is required. Both parties must demonstrate the ability to perform data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing shall not affect its ability to offer electric generation to Direct Access customers. Dual Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.

5.1.7. Compliance testing will be required for a MRSP when providing meter reading services to ensure that meter data can be delivered successfully. Any change of the MRSP's system, or any change to the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing.

6 Direct Access Service Request (DASR)

6.1 A DASR is submitted pursuant to the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and shall also be used to define the Competitive Services that the ESP will provide the customer.

6.2 ESPs shall have a CC&N from the ACC; shall have entered into an ESP Service Acquisition Agreement with Company, if required, and shall have successfully completed data exchange compliance testing before submitting DASRs.

6.3 The customer's authorized ESP must submit a completed DASR to Company before Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein shall be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.

6.4. A separate DASR must be submitted for each service delivery point. Each of the five (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to Company. A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing DASRs are thereby representing that they have their customer's authorization for such transaction.

6.5. Company requires that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the Company's web site (http://esp.apsc.com).

6.6. DASRs will be handled on a first-come, first-served basis. Each request shall be time and date stamped when received by Company.

6.7 Once the DASR is submitted, the following timeframes will apply:

6.7.1. Company will respond to RQ, TS, CL and UC DASRs within two (2) working days of the time and date stamp. Company will exercise best efforts (no later than five (5) working days) to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 and will be confirmed in the response to the ESP and the former ESP if applicable. If a DASR is rejected, Company shall provide the reasons for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed with the required information within thirty (30) working days, or a mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.

6.7.2. When a customer requests electric services to be disconnected, the ESP is responsible for submitting a PD DASR to Company on behalf of the customer, regardless of the Meter Service Provider (MSP).

6.7.2.1. When Company is acting as the MSP, Company shall perform the physical disconnect of the service. The PD DASR must be received by Company at least three (3) working days prior to the requested disconnect date. Company will acknowledge the PD DASR status within two (2) working days of the time and date stamp.

6.7.2.2 When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP shall notify Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the server within three (3) working days following the disconnection.

6.8. DASRs that do not require a meter exchange must be received by Company at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date would be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

6.9 DASRs that require a meter exchange will have an effective change date to Direct Access as of the meter exchange date. Notification of meter exchange dates shall be coordinated between the ESP, MSP and Company's Meter Activity Coordinator ("MAC").

6.10. If more than one (1) RQ DASR is received for a service delivery point within a Customer's billing cycle, only the first valid DASR received shall be processed in that period. All subsequent DASRs shall be rejected.

6.11. Upon acceptance of an RQ DASR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP shall be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date.

6.12. Customers returning to Company Standard Offer service must contact their ESP. The ESP shall be responsible for submitting the DASR on behalf of the customer.

6.13. ESPs requesting to return a Direct Access customer to Company Standard Offer service shall submit a TS DASR and shall be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.

6.14. Customers requesting to return to Company Standard Offer service are subject to the same timing requirements as used to establish Direct Access service. Direct Access customers returning to Company Standard Offer service may be subject to the RCDAC-1.

6.15. Company may assess a fee for processing DASRs. All fees are payable to Company within fifteen (15) calendar days after the invoice date. All unpaid fees received after this date will be assessed applicable late fees pursuant to Schedule 1. If an ESP fails to pay these fees within thirty (30) days after the due date, Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the fees due is currently available or until such time as the fees are paid. If an ESP is late in paying fees, a deposit or an additional deposit may be required from the ESP.

6.16. A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact Company to establish a Service Account. The customer will be provided the necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in Section 6.8 and 6.9.

6.17. Billing and metering option changes are requested through a UC DASR and cannot be changed more than once per billing cycle.

6.18. Company shall not hold the ESP responsible for any customer unpaid billing charges prior to the customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs and shall remain the customer's responsibility to pay Company. Company's Schedule 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. Company shall not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by Company of a delinquent customer shall not make Company liable to the ESP or third-parties for the customer's disconnection.

6.19 Company shall not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7 Billing Service Options and Obligations

7.1 Subject to availability, and pursuant to the terms in the ESP Service Acquisition Agreement, this Schedule 10, and applicable tariffs and the restrictions therein, ESPs may select among the following billing options:

7.1.1 COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL COMPANY/ESP BILLING

7.2 COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to Company, and Company sends a consolidated bill containing both Company and ESP charges to the Customer.

7.2.2 Company Obligations:

7.2.2.1 Company shall bill the ESP charges and send the bill either by mail or electronic means to the customer. Company is not responsible for computing or determining the accuracy of the ESP charges. Company is not required to estimate ESP charges if the expected bill ready data is not received nor is Company required to delay Company billing. Billing rendered on behalf of the ESP by Company shall comply with A.A.C. R14-2-1612.

7.2.2.2 Company bills shall include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.

7.2.2.3 If Company processes Customer payments on behalf of the ESP, the ESP shall receive payment for its charges as specified in Section 7.7.

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer Company UDC Consolidated Billing services to Direct Access customers pursuant to the terms and conditions of the applicable ACC approved tariff.

7.2.3.2. The ESP shall submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to Company's meter reading schedule, and pursuant to the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1. Bills under this option will be rendered once a month. Nothing contained in this Schedule shall limit Company's ability to render bills more frequently consistent with Company's existing practices. However, if Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2. Except as provided in Section 7.2.4.1, Company shall require that all ESP and Company charges be based on the same billing period data.

7.2.4.3. ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this deadline, Company will render a bill for Company charges only. The ESP must wait until the next billing cycle, unless there is a mutual agreement for Company to send an interim bill. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that Company charges were previously billed.

7.2.4.4. ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, Company will render the customer's final bill for Company charges only, without the ESP's final charges. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5 Restrictions

Company UDC Consolidated Billing shall be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under Company UDC Consolidated Billing.

7.3. ESP CONSOLIDATED BILLING

7.3.1 Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP shall be obligated to provide the customer detailed Company charges to the extent that the ESP receives such detail from Company. The ESP is not responsible for the accuracy of Company charges.

7.3.2 Company Obligations:

7.3.2.1 Company shall calculate all its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. Company and the ESP may mutually agree to alternative options for the calculation of Company charges.

7.3.2.2 Company shall provide the ESP with sufficient detail of its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming.

7.3.2.3 For a Physical Disconnect Final Bill, Company will provide the ESP with Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges. The ESP shall include a message on the bill stating that Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

7.3.3 ESP Obligations:

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill shall include any billing-related details of Company charges. Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of Company by the ESP shall comply with A.A.C. R14-2-1612.

7.3.3.3 Other than including the billing data provided by Company on the customer's bill, the ESP has no obligations regarding the accuracy of Company charges or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.

7.3.3.4 The ESP shall process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all charges due to Company and not disputed by the customer as specified in Section 7.7.2.1.

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer customers customized billing cycles or payment plans which permit the Customer to pay the ESP for Company charges in different amounts than Company charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay all Company charges in full. Should Customer select an optional payment plan, all Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

ESPs may render bills more or less frequently than once a month. However, Company shall continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY/ESP BILLING

Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company and the ESP. Company and the ESP shall process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, Company shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If Company is providing Consolidated billing services, Company shall continue to provide these notices.

7.5.2 Under Company UDC Consolidated Billing, ESP bill inserts may be included pursuant to the applicable Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or Company if providing such services) shall resolve any meter errors and must notify the ESP and Company, as applicable, so any billing adjustments can be made. All other affected parties, including the appropriate Scheduling Coordinator, shall be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of Customer's energy or demand. If the MSP, MRSP, ESP or Company becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 Company UDC Consolidated Billing

7.6.1.3.1 Company shall be responsible for notifying Customer and adjusting the bill for its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP shall be responsible for any recalculation of the ESP charges. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to Customer's next normal monthly bill, unless there is mutual agreement to have Company send an interim bill to the Customer including the ESP's charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP shall be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer shall be solely responsible for obtaining refunds of ESP electric generation overcharges from its current and prior ESPs, as appropriate.

7.6.1.4.2 Company shall transmit its adjusted charges and any refunds to the ESP with Customer's next normal monthly bill. The ESP shall apply the charges to Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to Customer including Company charges.

7.6.1.5 Dual Company/ESP Billing

7.6.1.5.1 Company and the ESP shall be separately responsible for notifying Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 Company UDC Consolidated Billing

7.7.1.1 Company shall remit payments to the ESP for the total ESP charges collected from Customer within three (3) working days after Customer's payment is received. Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by Company.

7.7.1.2 Customer is obligated to pay Company for all undisputed Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing services agreement between ESP and Company.

7.7.1.4 Payment for any Company charges for Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date Company charges are rendered to the ESP. Any payment not received within this time frame will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 Payment is due in full from the ESP within fifteen (15) calendar days after the date Company's charges are rendered to the ESP. The ESP shall pay all undisputed Company charges regardless of whether Customer has paid the ESP. All payments received after fifteen (15) calendar days will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2.2 Company shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual Company/ESP Billing

Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 Company UDC Consolidated Billing

7.8.1.1 Company shall not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All Customer payments shall be applied first to unpaid balances identified as Company charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212, but a Customer will not otherwise have the right to direct partial payments between Company and the ESP.

7.8.1.3 ACC rules shall apply to late or non-payment of all Company customer charges. Undisputed Company delinquent balances owed on a customer account shall be considered late and subject to Company late payment procedures.

7.8.2 ESP Consolidated Billing

The ESP shall be responsible for collecting both unpaid ESP and Company charges, sending notices informing Customers of unpaid ESP and Company balances, and taking appropriate actions to recover the amounts owed. Company shall not assume any collection obligations under this billing option and ESP is liable to Company for all undisputed payments owed Company.

7.8.3 Dual Company/ESP Billing

Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with Company charges must be directed to Company.

7.9 Service Disconnects and Reconnects

In accordance with ACC rules, Company has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of Company's final bills or any past due charges by Customer, or evidence of safety violations, energy theft, or fraud, by Customer. The following provides for service disconnects and reconnects.

7.9.1 Company shall notify Customer and Customer's ESP of Company's intent to disconnect electric service for the non-payment of Company charges prior to disconnecting electric service to the Customer. Company shall further notify the ESP at the time Customer has been disconnected. To the extent authorized by the ACC, a service charge shall be imposed on Customer if a field call is performed to disconnect electric service.

7.9.2 Company shall reconnect electric service for a fee when the criteria for reconnection have been met to Company's satisfaction. Company shall notify the ESP of a Customer's reconnection.

7.9.3 Company shall not disconnect electric service to Customer for the non-payment of ESP charges by Customer. In the event of non-payment of ESP charges by Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to Company Standard Offer Service. Company will then advise the Customer that they will be placed on Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10. Involuntary Service Changes

7.10.1. A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

7.10.1.1. The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and Company exercises a contractual right to change billing options.

7.10.1.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.5. The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and Company tariffs and schedules.

7.10.2. Change of Service Election in Exigent Circumstances

In the event Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company elects to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, Company shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule. Company shall provide such notice and opportunity to remedy the problem if there are reasonable circumstances prevailing. Additionally, Company shall notify the ACC of the circumstances that required the change or the termination and the resulting action taken by Company. The ESP and/or Customer shall have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to Customer other than as provided in Section 4.4.2 .

7.10.3. Change in Service Election Absent Exigent Circumstances

7.10.3.1. In the event Company finds that an ESP has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company seeks to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3), and the failure does not constitute an emergency (as defined in Section 7.10.2) or involve an ESP's unauthorized energy use, Company shall notify the ESP and the ACC of such finding in writing stating the following:

7.10.3.1.1. The nature of the alleged failure;

7.10.3.1.2. The actions necessary to remedy the failure;

7.10.3.1.3. The name, address and telephone number of a contact person at the Company authorized to discuss resolution of the failure.

7.10.3.2. The ESP shall have thirty (30) calendar days from receipt of such notice to remedy the alleged failure or reach an agreement with Company regarding the alleged failure. If the failure is not remedied and no agreement is reached between Company and the ESP following this thirty (30) day period, Company may initiate the DASR process set forth in this Schedule to accomplish its remedy and shall notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the customer other than as provided in Section 4.4.2.

7.10.4. Termination of ESP Consolidated Billing

7.10.4.1. Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.1.1. The Company shall notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:

7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.

7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.

7.10.4.1.1.3 The ESP files for bankruptcy.

7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.

7.10.4.1.1.5 The ESP admits insolvency.

7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.

7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.

7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.

7.10.4.1.2. If the ESP fails to pay Company (or dispute payment pursuant to the procedures set forth in this Schedule) the full amount of all Company charges and fees by the applicable due date, Company shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by Company, Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.1.3. If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from Company of any additional credit, security or deposit requirements set forth in Sections 5.1.3 and 7.11, Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.2. Upon termination of ESP Consolidated Billing pursuant to Section 7.10.4, Company may deliver a separate bill for all Company charges which were not previously billed by the ESP.

7.10.4.3 Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections 5.1.4 and 7.11, and payment to Company of all costs associated with changing ESP customers' billing elections to and from dual billing.

7.10.4.4 In the event Company terminates ESP Consolidated Billing, Company will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.

7.10.5. Termination of Company UDC Consolidated Billing

7.10.5.1. Company may terminate Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to pay Company charges in connection with Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2.

7.10.5.2 Company may terminate Consolidated Billing upon providing thirty (30) days notice to an ESP if Company cancels or changes the tariff governing Company UDC Consolidated Billing.

7.10.6. Upon termination of ESP Direct Access services pursuant to Section 7.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by Customer, Company shall provide such services, until such time that Customer makes an election.

7.10.7. Company shall not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11. ESP Security Deposits

7.11.1. Company may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to pay Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through Schedule 10 and Company's other tariffs and schedules.

7.11.2. The amount of the security deposit required shall not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3. Security deposits required pursuant to Section 7.11 shall be in the form of a cash deposit accruing interest as specified in Section 2.7.4 of Company Schedule 1. Company shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4. Company may refuse to accept DASRs from, or provide other Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit pursuant to Section 7.11.

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, MSP and MRSP services.

8.2 Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for Residential Load-Profiled Customers

8.2.2 Services as authorized by the ACC.

8.2.3 Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for Company charges.

8.3 A Load Serving ESP may sub-contract Metering or Meter Reading Services to a certificated third party. If the ESP sub-contracts any of the components of these services to a third party, the ESP shall, for the purposes of this Schedule, remain responsible for the services.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work..

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test
ANSI 57.13	Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 NEC & Local Requirements by jurisdictions

8.5.6 Company's Electric Service Requirements Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Company's rate schedules.

8.6.2 If Company is providing MRSP functions for the ESP, pursuant to the Rules, meters must be compatible with Company's meter reading system.

8.6.3 No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet approved specifications, as set forth in Company's ESRM, or is in violation of any code listed in Section 8.5.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service shall be processed according to the following table prior to its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph kWh Electro-Mechanical	Trouble	Meter Test
1 Ph kWh Hybrid or Solid State	Routine	Meter Test
1 Ph TOU (all)	Trouble	Meter Test
3 Ph Meters (all)	All	Meter Test
1 Ph or 3 Ph IDR Meters	All	Meter Test

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.4 Records on meter testing shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest meter test record shall be kept as long as the meter is in service.

8.8 Meter Test Requests

Pursuant to A.A.C. R14-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP shall take reasonable measures to detect meter error. The MSP shall notify Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error. ESPs and Company shall use a form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.

8.9 Meter Identification

8.9.1 The ESP or its agent shall install a Company provided unique number on each meter. Company will provide the unique numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter shall remain solely with that meter while in use in Company's service territory.

8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a blue seal that is imprinted with the name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

8.10.1 All metering equipment shall be installed according to all applicable ACC requirements and Company's Electric Service Requirements Manual.

8.10.2 An ESP or its agent must be authorized by Company to remove a Company owned meter. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days prior to the exchange.

Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.

8.10.3 The ESP or its agent shall inform Company of all meter activity, such as meter installations or exchanges, via the Meter Activity Coordination (MAC) Form within the time frames specified above. If final meter reads are not provided to Company, are inaccurate, or otherwise result in Company not being able to render accurate final bills to customers pursuant to ACC Rules and Regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

8.10.4 The ESP or its agent shall return the existing meter to Company at one of Company's designated locations identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent shall be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 Company may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

8.11.2 For new construction, the party installing the meter shall ensure that the owner/builder has met the construction standards outlined in Company's ESRM, and Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements. Company shall perform a preinstallation inspection on all new construction. Local city/county clearances may also be required prior to energizing any new construction.

8.11.3 Company may require a site meet for: the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which Company forbids key access; cogeneration sites, bi-directional or detented metering sites; or upon request of an ESP or MSP. The ESP and Company's MAC shall coordinate the time of the site meet. If the ESP or MSP miss two (2) site meets, Company may cancel the applicable DASR. Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership shall be limited to Company, an ESP, or the customer. The customer must obtain the meter through Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 If the ESP or customer owns the meter, the ESP must own the CTs, PTs, and associated equipment, except as provided in Section 8.12.3. The ESP may purchase existing CTs and PTs and associated metering equipment from Company.

8.12.3 The following provisions apply to the ownership of CTs and PTs.

8.12.3.1 For distribution voltages up to 25kV, the ESP or Company shall own the CTs and PTs. For transmission primary voltages (over 25kV), the CTs and PTs shall be owned by Company. ESP owned CTs and PTs must meet Company specifications. No CTs and PTs or associated metering equipment shall be set or allowed to remain in service if it is determined that the CTs and PTs or their associated equipment does not meet Company's approved specifications, as set forth in Company's Electric Service Requirements Manual in place at the time of installation.

8.12.4 All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in Company's ESRM. During meter exchanges, the ESP or its agent's employees who are certificated to perform the related MSP activities may install, replace or operate Company test switches and operate Company-sealed customer-owned test blocks.

8.13 Installation Options

8.13.1 The ESP is responsible for Direct Access customer meter installation. Company may optionally provide meter installation pursuant to the Rules.

8.13.2 ESPs or their agents must be certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP and their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certificated MSP.

8.13.2.2 Subcontracting with a third party that is a certificated MSP.

8.13.2.3 Subcontracting with Company under the circumstances described in Section 8.2.

8.14 As part of providing metering services, ESPs or their agents shall:

8.14.1 Obtain lock ring keys for meters originally installed by Company or request site meets with Company. Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the Company MAC.

8.14.2 If lock rings are used they shall meet Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from Company.

8.14.3 Provide information to Company on the specifications and other specifics on meters not purchased from or installed by Company.

8.14.4 Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows Company to remove meters, ESP shall coordinate with Company regarding the return of the meters.

8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.

8.14.6 Ensure that ESP and MSP employees working in Company's territory follow ACC and other applicable safety standards.

8.14.7 Company shall notify the ESP immediately and the ESP shall notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP shall ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and shall notify the ACC of any such action taken.

8.14.8 Take no action to impede Company's safe and unrestricted access to a customer's service entrance.

8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

8.15 MSRP Services provided as a responsibility of an ESP

Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations shall perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least ten (10) days prior to the next scheduled read date. MRSP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1 Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file shall be posted immediately.

8.15.2 Both Company and the ESP shall have 24-hour/7 days per week access to the MRSP server.

8.15.3 Meter read data shall include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data shall be provided for all interval metering customers. Data must be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated data shall contain applicable reason codes pursuant to the 867 guidelines.

8.15.4 The MRSP shall provide Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.6 MRSPs shall read Customer's meter based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter shall contain the full period from read date to the following read date. Interval data cycles shall be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp shall begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 shall constitute the billing cycle. For meter exchanges back to Standard Offer, every interval shall be included up to the last full interval prior to the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.

8.15.7 The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by Company or Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for all meters.

8.16.1.1 Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

8.16.1.2 Meter read date and time shall be accurate.

8.16.1.3 All meter reading data shall be validated pursuant to the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

Pursuant to guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data shall be available by 3:00 p.m. Local Arizona Time (MST) on the third working day after the scheduled read date. If the meter data is not posted, is unavailable, or clearly contains errors by this deadline, the billing determinants including usage (kWh) and demand (kW) may be estimated by Company and the ESP shall be charged an approved charge for this service.

8.16.3 Proof of Operational Ability

Prior to performing MRSP services in Company's distribution service territory, or prior to making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in Company's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a Customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server shall be stored in Company-compatible EDI format.

8.17 Company performing MSP and MRSP functions:

If Company is eligible to perform Direct Access related MSP and MRSP functions as defined in section 8.2, the following restriction applies:

The validated meter read will be posted in EDI format no later than 6 working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the affected Customer. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party may be charged an ACC-approved tariff for the meeting.

8.18.2.2 Company may repair the defect, and the other party shall be responsible for all related expenses.

8.18.2.3 Company shall adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

8.18.3 Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to section 7.10.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

APPENDIX G SCHEDULE 4

TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

Arizona Public Service Company (Company) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SESs) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single site.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 7 are all satisfied.

1. The customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1) ; and
2. Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and
3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and
4. For Standard Offer customers, totalized metering must be accomplished by a physical wire interconnection of metering information with the customer providing conduit between the SESs; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule 10, Terms and Conditions for Direct Access; and
5. The customer shall provide vault or transformer space, which meets Company specifications, on the customer's property at no cost to Company; and
6. If the customer operates an electric generation unit on the premise, totalized metering will be permitted when the customer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected customer owned generation; and
7. Written approval by Company's authorized representative is required before totalized metering may be implemented.

B. Adjacent Totalized Metering will apply when conditions A.1-A.7 and the following conditions are met:

1. The customer's <u>total</u> load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and
2. Company requires that load be split and served from multiple SESs; and
3. The customer must locate SESs to be totalized within 10 feet of each other.

There will be no additional charge to the customer's monthly bill for Adjacent Totalized Metering.

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SCHEDULE 4
TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

C. Remote Totalized Metering will apply when conditions A.1-A.7 are met, multiple SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

2. The customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

3. The customer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the customer receiving Remote Totalized Metering. However, lower capital investment which results from the customer's contribution, other than the meter costs in C.3 above, shall not be considered.

For customers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus $500.00, plus all applicable taxes and adjustments.

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.

2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.

3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

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APPENDIX H SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

Arizona Public Service Company (Company) will provide specialized metering upon customer request, provided the customer agrees to the following conditions:

1. The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR and KYZ pulse meters. The customer must specify whether a modem will be required.

2. If the customer requests a meter with a modem option, the customer will be required to install communication equipment and connections which shall include a RJ11 or RJ12 jack. A coil of communication cable with either an RJ11 or RJ12 jack is to be provided within five to ten feet of the meter panel location and in such a manner that will provide for ease of attachment of the jack to the meter panel by Company. The phone line must be installed prior to the installation of the meter. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).

3. If a customer requests kWh pulses, Company shall furnish an isolation relay and maintain the output wire and connections from this relay to an approved terminal block to be furnished by the customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) the Company metering compartment and not on the face of the Company metering panel.

4. The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

   4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.

   4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.

   4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

   Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

   Company will retain ownership of all meters and Company installed metering equipment.

   If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.

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SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the customer stop the operation or in any way affect or interfere with the operation of the isolation relay and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.

6. Company reserves the right to interrupt the specialized metering circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the customer's demand control or other equipment. However, Company will make a good faith effort to notify the customer prior to any interruption of the specialized metering circuit.

7. The possible failure or malfunction of an isolation relay and subsequent loss of kWh contact closures to the customer's control equipment shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the kWh and demand record for billing purposes.

8. The accuracy of the customer's equipment is entirely the responsibility of the customer. Should the customer's equipment malfunction, Company will reasonably cooperate with the customer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the customer, unless the actual source of the malfunction is found within Company's equipment.

9. If Company provides pulse values in kWh, customer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.

10. No circuit for use by the customer shall be installed from Company's billing metering potential or current transformer secondaries.

11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the customer.

12. Upon request by Company, the customer shall make available to Company monthly load analysis information.

13. References to electric kWh pulses above shall mean isolation relay contact closures only; the customer is required to furnish operating voltage service. Isolation relay contacts are rated 5 amps, 28 volts DC or 120 volts AC.

14. The customer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of specialized metering.

15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.

SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

16. Prior written approval by an authorized Company representative is required before electric kWh pulses service may be implemented.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST-OF-SERVICE
PALO VERDE UNIT I
(Thousands of Dollars)
(APS Share)

Line	Year	Post Shutdown On-Going ISFSI Annual Contribution Required	Post Shutdown ISFSI Regulatory Asset Amortization Annual Contribution Required	Decommissioning Annual Contribution Required	Total Annual Contribution Required	ACC Jurisdictional Amount /1/
1	2004	$ 125	$ 107	$ 4,077	$ 4,309	$ 4,246
2	2005	251	214	5,122	5,587	5,505
3	2006	251	214	5,122	5,587	5,505
4	2007	251	214	5,122	5,587	5,505
5	2008	251	214	5,122	5,587	5,505
6	2009	605	214	5,122	5,941	5,854
7	2010	960	214	5,122	6,296	6,204
8	2011	960	214	5,122	6,296	6,204
9	2012	960	214	5,122	6,296	6,204
10	2013	960	214	5,122	6,296	6,204
11	2014	960	214	5,122	6,296	6,204
12	2015	960	214	5,122	6,296	6,204
13	2016	960	214	5,122	6,296	6,204
14	2017	960	214	5,122	6,296	6,204
15	2018	960	214	5,122	6,296	6,204
16	2019	960	214	5,122	6,296	6,204
17	2020	960	214	5,122	6,296	6,204
18	2021	960	214	5,122	6,296	6,204
19	2022	960	214	5,122	6,296	6,204
20	2023	960	214	5,122	6,296	6,204
21	2024	960	214	5,122	6,296	6,204
22	2025	-	-	-	-	-
23	2026	-	-	-	-	-
		$ 16,134	$ 4,387	$ 106,517	$ 127,038	$ 125,183

/1/ ACC Jurisdictional share is approximately 98.54%.

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DECISION NO. ______

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST-OF-SERVICE
PALO VERDE UNIT II
(Thousands of Dollars)
(APS Share)

Line	Year	Post Shutdown On-Going ISFSI Annual Contribution Required	Post Shutdown ISFSI Regulatory Asset Amortization Annual Contribution Required	Decommissioning Annual Contribution Required	Total Annual Contribution Required	ACC Jurisdictional Amount /1/
1	2004	$ 126	$ 194	$ 6,153	$ 6,473	$ 6,378
2	2005	250	388	8,072	8,710	8,583
3	2006	250	388	8,072	8,710	8,583
4	2007	250	388	8,072	8,710	8,583
5	2008	250	388	8,072	8,710	8,583
6	2009	606	388	8,072	9,066	8,934
7	2010	2,561	388	8,072	11,021	10,860
8	2011	2,561	388	8,072	11,021	10,860
9	2012	2,561	388	8,072	11,021	10,860
10	2013	2,561	388	8,072	11,021	10,860
11	2014	2,561	388	8,072	11,021	10,860
12	2015	2,561	388	8,072	11,021	10,860
13	2016	-	-	-	-	-
14	2017	-	-	-	-	-
15	2018	-	-	-	-	-
16	2019	-	-	-	-	-
17	2020	-	-	-	-	-
18	2021	-	-	-	-	-
19	2022	-	-	-	-	-
20	2023	-	-	-	-	-
21	2024	-	-	-	-	-
22	2025	-	-	-	-	-
23	2026	-	-	-	-	-
		$ 17,098	$ 4,462	$ 94,945	$ 116,505	$ 114,804

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST-OF-SERVICE
PALO VERDE UNIT III
(Thousands of Dollars)
(APS Share)

Line	Year	Post Shutdown On-Going ISFSI Annual Contribution Required	Post Shutdown ISFSI Regulatory Asset Amortization Annual Contribution Required	Decommissioning Annual Contribution Required	Total Annual Contribution Required	ACC Jurisdictional Amount /1/
1	2004	$ 125	$ 95	$ 5,098	$ 5,318	$ 5,240
2	2005	251	190	6,017	6,458	6,364
3	2006	251	190	6,017	6,458	6,364
4	2007	251	190	6,017	6,458	6,364
5	2008	251	190	6,017	6,458	6,364
6	2009	605	190	6,017	6,812	6,713
7	2010	960	190	6,017	7,167	7,062
8	2011	960	190	6,017	7,167	7,062
9	2012	960	190	6,017	7,167	7,062
10	2013	960	190	6,017	7,167	7,062
11	2014	960	190	6,017	7,167	7,062
12	2015	960	190	6,017	7,167	7,062
13	2016	960	190	6,017	7,167	7,062
14	2017	960	190	6,017	7,167	7,062
15	2018	960	190	6,017	7,167	7,062
16	2019	960	190	6,017	7,167	7,062
17	2020	960	190	6,017	7,167	7,062
18	2021	960	190	6,017	7,167	7,062
19	2022	960	190	6,017	7,167	7,062
20	2023	960	190	6,017	7,167	7,062
21	2024	960	190	6,017	7,167	7,062
22	2025	960	190	6,017	7,167	7,062
23	2026	1,004	238	6,017	7,259	7,153
		$ 18,098	$ 4,323	$ 137,472	$ 159,893	$ 157,559

/1/ ACC Jurisdictional share is approximately 98.54%.

DECISION NO. 67744

APPENDIX J

Settlement Rates for Residential Customers

Schedule E-10

Bundled Rate:	
Summer	
BSC (per day)	$ 0.253
1st 400 kWh	0.06929
Next 400 kWh	0.09490
additional kWh	0.09760
Winter	
BSC (per day)	$ 0.253
All kWh	0.07601
Generation:	
Summer	
1st 400 kWh	0.03518
Next 400 kWh	0.06079
additional kWh	0.06349
Winter	
All kWh	0.04190
Transmission:	
Summer	
All kWh	0.00476
Winter	
All kWh	0.00476
Distribution:	
Summer	
BSC (per day)	$ 0.253
All kWh	0.02722
Winter	
BSC (per day)	$ 0.253
All kWh	0.02722
System Benefits:	
Summer	
All kWh	0.00213
Winter	
All kWh	0.00213
BSC: (per day)	
Customer Accts	$ 0.063
Metering	$ 0.073
Billing	$ 0.062
Meter Reading	$ 0.055
BSC Total	$ 0.253

Schedule E-12

Bundled Rate:	
Summer	
BSC (per day)	$ 0.253
1st 400 kWh	0.07570
Next 400 kWh	0.10556
additional kWh	0.12314
Winter	
BSC (per day)	$ 0.253
All kWh	0.07361
Generation:	
Summer	
1st 400 kWh	0.04007
Next 400 kWh	0.06993
additional kWh	0.08751
Winter	
All kWh	0.03798
Transmission:	
Summer	
All kWh	0.00476
Winter	
All kWh	0.00476
Distribution:	
Summer	
BSC (per day)	$ 0.253
All kWh	0.02874
Winter	
BSC (per day)	$ 0.253
All kWh	0.02874
System Benefits:	
Summer	
All kWh	0.00213
Winter	
All kWh	0.00213
BSC: (per day)	
Customer Accts	$ 0.056
Metering	$ 0.081
Billing	$ 0.062
Meter Reading	$ 0.055
BSC Total	$ 0.253

Schedule EC-1

Bundled Rate:	
Summer	
BSC (per day)	$ 0.329
All kWh	0.03943
per kW	$ 10.00
Winter	
BSC (per day)	$ 0.329
All kWh	0.02978
kW	$ 7.10
Generation:	
Summer	
All kWh	0.01821
per kW	$ 7.66
Winter	
All kWh	0.00995
per kW	$ 5.08
Transmission:	
Summer	
All kWh	0.00476
Winter	
All kWh	0.00476
Distribution:	
Summer	
BSC (per day)	$ 0.329
All kWh	0.01433
per kW	$ 2.34
Winter	
BSC (per day)	$ 0.329
All kWh	0.01294
per kW	$ 2.02
System Benefits:	
Summer	
All kWh	0.00213
Winter	
All kWh	0.00213
BSC: (per day)	
Customer Accts	$ 0.049
Metering	$ 0.163
Billing	$ 0.062
Meter Reading	$ 0.055
BSC Total	$ 0.329

Schedule ECT-1R

Bundled Rate:	
Summer	
BSC (per day)	$ 0.493
On-peak kWh	0.04765
Off-peak kWh	0.02672
On-peak - kW	$ 11.81
Winter	
BSC (per day)	$ 0.493
On-peak kWh	0.0364[illegible]
Off-peak kWh	0.02570
On-peak - kW	$ 8.11
Generation:	
Summer	
On-peak kWh	0.03113
Off-peak kWh	0.01020
On-peak - kW	$ 8.43
Winter	
On-peak kWh	0.01608
Off-peak kWh	0.00537
On-peak - kW	$ 6.26
Transmission:	
Summer	
All kWh	0.00476
Winter	
All kWh	0.00476
Distribution:	
Summer	
BSC (per day)	$ 0.493
All kWh	0.00963
On-peak - kW	$ 3.38
Winter	
BSC (per day)	$ 0.493
All kWh	0.01344
On-peak - kW	$ 1.85
System Benefits:	
Summer	
All kWh	0.00213
Winter	
All kWh	0.00213
BSC: (per day)	
Customer Accts	$ 0.208
Metering	$ 0.168
Billing	$ 0.062
Meter Reading	$ 0.055
BSC Total	$ 0.493

Schedule ET-1

Bundled Rate:	
Summer	
BSC (per day)	$ 0.493
On-peak kWh	0.13310
Off-peak kWh	0.04299
Winter	
BSC (per day)	$ 0.493
On-peak kWh	0.10918
Off-peak kWh	0.04167
Generation:	
Summer	
On-peak kWh	0.10527
Off-peak kWh	0.01516
Winter	
On-peak kWh	0.08135
Off-peak kWh	0.01384
Transmission:	
Summer	
All kWh	0.00476
Winter	
All kWh	0.00476
Distribution:	
Summer	
BSC (per day)	$ 0.493
All kWh	0.02094
Winter	
BSC (per day)	$ 0.493
All kWh	0.02094
System Benefits:	
Summer	
All kWh	0.00213
Winter	
All kWh	0.00213
BSC: (per day)	
Customer Accts	$ 0.211
Metering	$ 0.166
Billing	$ 0.062
Meter Reading	$ 0.055
BSC Total	$ 0.493

August 10, 2004

Settlement Rate for Schedule E-32

E-32 Rate (20 kW or Less)		
Bundled Rate:		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
Summer		
kWh (1st 5000 / mo.) (Secondary)	$	0.09892
kWh (over 5000 / mo.) (Secondary)	$	0.04711
kWh (1st 5000 / mo.) (Primary)	$	0.09610
kWh (over 5000 / mo.) (Primary)	$	0.04429
Winter		
kWh (1st 5000 / mo.) (Secondary)	$	0.08892
kWh (over 5000 / mo.) (Secondary)	$	0.03711
kWh (1st 5000 / mo.) (Primary)	$	0.08610
kWh (over 5000 / mo.) (Primary)	$	0.03429
Primary Discount (per kWh)	$	0.00282
Generation		
Summer		
kWh (1st 5000 / mo.)	$	0.05894
kWh (over 5000 / mo.)	$	0.03163
Winter		
kWh (1st 5000 / mo.)	$	0.04901
kWh (over 5000 / mo.)	$	0.02170
Transmission		
per kWh	$	0.00476
Delivery		
Summer		
Delivery (1st 5000 kWh per mo.) (Secondary)	$	0.03309
Delivery (over 5000 kWh per mo.) (Secondary)	$	0.00859
Delivery (1st 5000 kWh per mo.) (Primary)	$	0.03027
Delivery (over 5000 kWh per mo.) (Primary)	$	0.00577
Winter		
Delivery (1st 5000 kWh per mo.) (Secondary)	$	0.03302
Delivery (over 5000 kWh per mo.) (Secondary)	$	0.00852
Delivery (1st 5000 kWh per mo.) (Primary)	$	0.03020
Delivery (over 5000 kWh per mo.) (Primary)	$	0.00570
System Benefits		
per kWh	$	0.00213
BSC (per day)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day charges)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

E-32 Rate (over 20 kW)		
Bundled Rate:		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
kW		
1st 100 kW (Secondary)	$	7.722
Next 400 kW (Secondary)	$	3.497
Over 500 kW (Secondary)	$	3.497
1st 100 kW (Primary)	$	7.102
Next 400 kW (Primary)	$	2.877
Over 500 kW (Primary)	$	2.877
Summer		
1 st 200 kWh/kW	$	0.07938
over 200 kWh/kW	$	0.04175
Winter		
1 st 200 kWh/kW	$	0.06945
over 200 kWh/kW	$	0.03182
Primary Discount (per kW)	$	0.620
Transmission Discount (per kW)	$	3.490
Generation		
Summer		
1 st 200 kWh/kW	$	0.07239
over 200 kWh/kW	$	0.03476
Winter		
1 st 200 kWh/kW	$	0.06246
over 200 kWh/kW	$	0.02483
Transmission		
per kWh	$	0.00476
Delivery		
Delivery 1st 100 kW (Secondary)	$	7.722
Delivery next 400 kW (Secondary)	$	3.497
Delivery kW over 500 (Secondary)	$	3.497
Delivery 1st 100 kW (Primary)	$	7.102
Delivery next 400 kW (Primary)	$	2.877
Delivery kW over 500 (Primary)	$	2.877
Delivery - All kWh	$	0.00010
System Benefits		
in $/kWh	$	0.00213
BSC (per day)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day charges)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

Settlement Rate for Schedule E-32 TOU

E-32TOU (20 kW or Less)		
Bundled Rate:		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
Summer		
kWh (1st 5000 / mo.) (Secondary) On-Pk	$	0.11172
kWh (over 5000 / mo.) (Secondary) On-Pk	$	0.05991
kWh (1st 5000 / mo.) (Secondary) Off-Pk	$	0.09172
kWh (over 5000 / mo.) (Secondary) Off-Pk	$	0.03991
kWh (1st 5000 / mo.) (Primary) On-Pk	$	0.10890
kWh (over 5000 / mo.) (Primary) On-Pk	$	0.05709
kWh (1st 5000 / mo.) (Primary) Off-Pk	$	0.08890
kWh (over 5000 / mo.) (Primary) Off-Pk	$	0.03709
Winter		
kWh (1st 5000 / mo.) (Secondary) On-Pk	$	0.10172
kWh (over 5000 / mo.) (Secondary) On-Pk	$	0.04991
kWh (1st 5000 / mo.) (Secondary) Off-Pk	$	0.08172
kWh (over 5000 / mo.) (Secondary) Off-Pk	$	0.02991
kWh (1st 5000 / mo.) (Primary) On-Pk	$	0.09890
kWh (over 5000 / mo.) (Primary) On-Pk	$	0.04709
kWh (1st 5000 / mo.) (Primary) Off-Pk	$	0.07890
kWh (over 5000 / mo.) (Primary) Off-Pk	$	0.02709
Primary Discount (per kWh)	$	0.00282
Generation		
Summer		
kWh (1st 5000 / mo.) On-Peak	$	0.07174
kWh (over 5000 / mo.) On-Peak	$	0.04443
kWh (1st 5000 / mo.) Off-Peak	$	0.05174
kWh (over 5000 / mo.) Off-Peak	$	0.02443
Winter		
kWh (1st 5000 / mo.) On-Peak	$	0.06181
kWh (over 5000 / mo.) On-Peak	$	0.03450
kWh (1st 5000 / mo.) Off-Peak	$	0.04181
kWh (over 5000 / mo.) Off-Peak	$	0.01450
Transmission		
per kWh	$	0.00476
Delivery		
Summer		
Delivery (1st 5000 kWh per mo.) (Secondary)	$	0.03309
Delivery (over 5000 kWh per mo.) (Secondary)	$	0.00859
Delivery (1st 5000 kWh per mo.) (Primary)	$	0.03027
Delivery (over 5000 kWh per mo.) (Primary)	$	0.00577
Winter		
Delivery (1st 5000 kWh per mo.) (Secondary)	$	0.03302
Delivery (over 5000 kWh per mo.) (Secondary)	$	0.00852
Delivery (1st 5000 kWh per mo.) (Primary)	$	0.03020
Delivery (over 5000 kWh per mo.) (Primary)	$	0.00570
System Benefits		
per kWh	$	0.00213
BSC (per day charges)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day charges)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

E-32 TOU (Over 20 kW)		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
kW		
1st 100 kW (Secondary) On-Peak	$	15.112
Next 400 kW (Secondary) On-Peak	$	10.887
Over 500 kW (Secondary) On-Peak	$	10.887
Residual kW (Secondary) Off-Peak	$	7.972
1st 100 kW (Primary) On-Peak	$	14.492
Next 400 kW (Primary) On-Peak	$	10.267
Over 500 kW (Primary) On-Peak	$	10.267
Residual kW (Primary) Off-Peak	$	7.352
Summer		
kWh On-Peak	$	0.04815
kWh Off-Peak	$	0.03815
Winter		
kWh On-Peak	$	0.03822
kWh Off-Peak	$	0.02822
Primary Discount (per kW)	$	0.620
Transmission Discount (per kW)	$	3.490
Generation		
1st 100 kW On-Peak	$	7.390
Next 400 kW On-Peak	$	7.390
Over 500 kW On-Peak	$	7.390
Residual kW Off-Peak	$	0.250
Summer		
kWh On-Peak	$	0.04116
kWh Off-Peak	$	0.03116
Winter		
kWh On-Peak	$	0.03123
kWh Off-Peak	$	0.02123
Transmission		
per kWh	$	0.00476
Delivery		
Delivery 1st 100 kW (Secondary)	$	7.722
Delivery next 400 kW (Secondary)	$	3.497
Delivery kW over 500 (Secondary)	$	3.497
Delivery - Residual kW Off-Peak	$	7.722
Delivery 1st 100 kW (Primary)	$	7.102
Delivery next 400 kW (Primary)	$	2.877
Delivery kW over 500 (Primary)	$	2.877
Delivery - Residual kW Off-Peak	$	7.102
Delivery - All kWh	$	0.00010
System Benefits		
in $/kWh	$	0.00213
BSC (per day charges)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day charges)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

DECISION NO. 67744

Settlement Rate for Schedules E-34 and E-35

Schedule E-34		
Bundled Rate		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
All kW		
All kW (Secondary)	$	12.343
All kW (Primary)	$	11.683
All kW (Transmission)	$	8.043
All kWh	$	0.03183
The numbers above reflect:		
Primary Discount (per kW)	$	0.660
Transmission Discount (per kW)	$	4.300
Generation		
Generation per kWh	$	0.02494
Generation per kW	$	7.740
Transmission		
per kWh	$	0.00476
Delivery		
Delivery per kWh	$	-
Delivery per kW (Secondary)	$	4.603
Delivery per kW (Primary)	$	3.943
Delivery per kW (Transmission)	$	0.303
System Benefits		
System Benefits per kWh	$	0.00213
BSC (per day)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

Schedule E-35		
Bundled Rate:		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
All kW		
On-Peak kW (Secondary)	$	12.869
On-Peak kW (Primary)	$	12.209
On-Peak kW (Transmission)	$	8.569
Off-Peak Excess kW (Secondary)	$	6.388
Off-Peak Excess kW (Primary)	$	5.728
Off-Peak Excess kW (Transmission)	$	2.088
On-Peak kWh	$	0.03529
Off-Peak kWh	$	0.02792
Primary Discount (per kW)	$	0.660
Transmission Discount (per kW)	$	4.300
Generation		
Generation per kWh - Peak	$	0.02840
Generation per kWh - Off-Peak	$	0.02103
Generation per kW - Peak	$	8.266
Generation per kW - Off Peak Excess	$	1.785
Transmission		
per kWh	$	0.00476
Delivery		
Delivery per kWh	$	-
Delivery per kW (Secondary)	$	4.603
Delivery per kW (Primary)	$	3.943
Delivery per kW (Transmission)	$	0.303
System Benefits		
per kWh	$	0.00213
BSC (per day charges)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day charges)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058
Note:		
On-peak period is 11AM-9PM		