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AZ CORP COMMISSION
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Transcript Exhibit(s)

Docket #(s): E-01345A-05-0816

E-01345A-05-0826

E-01345A-05-0827

Arizona Corporation Commission
DOCKETED

DEC 29 2006

DOCKETED BY

Exhibit # : S1-S18, S19-S25, S27

(Part 1 of 9)

Witness:
J. Dittmer

EXHIBIT
Admitted

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
RECONCILIATION OF POSITIONS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

Sch/ Adj. Ref.	Description	Company Position	Amount	Difference In Pretax Return	Revenue Requirement Value
	(A)		(B)	(C)	(D)
Sch. A	APS PROPOSED REVENUE REQUIREMENT				$ 453,931
Sch. B	RETURN DIFFERENCE (on APS Proposed Rate Base)	(c)	$ 4,466,697	-1.120%	(50,027)
	SUBTOTAL - REVENUE REQUIREMENT				$ 403,904
				Pre-Tax Return	
	RATE BASE ADJUSTMENTS				
B-1	SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT	(b)	$ (3,661)	11.63%	$ (426)
B-2	CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE	(c)	(2,873)	11.63%	(334)
B-3	INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE	(c)	(767)	11.63%	(89)
B-4	CASH WORKING CAPITAL	(c)	(57,018)	11.63%	(6,632)
B-5	**reserved**		-	11.63%	-
B-6	**reserved**		-	11.63%	-
B-7	**reserved**		-	11.63%	-
B-8	**reserved**		-	11.63%	-
	TOTAL VALUE OF STAFF RATE BASE ADJUSTMENTS		(64,320)		$ (7,481)
	STAFF RATE BASE RECOMMENDATION		$ 4,402,377		
				Revenue Conversion Multiplier	
SCH. A	**Company Proposed Net Operating Income**		$ 115,904		
	NET OPERATING INCOME ADJUSTMENTS				
C-1	REVERSE ESTIMATED CONSERVATION IMPACT FROM DSM	(c)	$ 2,991	1.6407	$ (4,907)
C-2	CORRECTION OF MISCELLANEOUS OTHER REVENUES	(a)	(11)	1.6407	17
C-3	NORMALIZE FUEL, PURCH POWER EXPENSE & OFF-SYSTEM SALE	(c)	64,094	1.6407	(105,158)
C-4	ELIMINATE M&T REVENUES & PURCHASE POWER EXPENSE	(a)	3,820	1.6407	(6,267)
C-5	ELIMINATE MARKETING AND TRADING O&M EXPENSES	(a)	5,042	1.6407	(8,273)
C-6	PENSION EXPENSE ADJUSTMENT	(c)	24,815	1.6407	(40,714)
C-7	POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT	(c)	2,417	1.6407	(3,965)
C-8	ELIMINATE ADDITIONAL MARKETING EXPENSES	(a)	310	1.6407	(508)
C-9	ELIMINATE NON-RECURRING SHARED SERVICES COSTS	(a)	4,835	1.6407	(7,933)
C-10	ELIMINATE SILVERHAWK RELATED LEGAL EXPENSES	(a)	58	1.6407	(95)
C-11	ELIMINATE SUNDANCE NON-ROUTINE MAINTENANCE EXPENSE	(c)	1,657	1.6407	(2,718)
C-12	ELIMINATE NON-RECURRING TAX RESEARCH COSTS	(a)	1,595	1.6407	(2,618)
C-13	ELIMINATE STOCK BASED INCENTIVE COMPENSATION	(c)	2,735	1.6407	(4,488)
C-14	ELIMINATE BARK BEETLE AMORT - DEFERRED PRE-RATE ORDER	(c)	305	1.6407	(500)
C-15	ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE	(c)	1,075	1.6407	(1,764)
C-16	NUCLEAR FUEL/ISFSI AMORTIZATION EXPENSE ADJUSTMENT	(a)	158	1.6407	(260)
C-17	ELIMINATE ESTIMATED INCREASE IN 2007 PWEC PROPERTY TAXE	(a)	1,029	1.6407	(1,689)
C-18	PRODUCTION TAX CREDIT ADJUSTMENT	(b)	959	1.6407	(1,573)
C-19	INTEREST SYNCHRONIZATION DEDUCTION ADJUSTMENT	(b)	(618)		-
C-20	CORRECT COS INCOME TAX EXPENSE ADJUSTMENT	(a)	4,838	1.6407	(7,938)
C-21	PV 1 STEAM GENERATOR DEPRECIATION EXPENSE	(a)	158	1.6407	(259)
C-22	INTEREST ON CUSTOMER DEPOSITS	(a)	(531)	1.6407	871
	TOTAL VALUE OF STAFF NET OPERATING INCOME ADJUSTMENTS		121,359		$ (200,365)
SCH. A	STAFF NET OPERATING INCOME RECOMMENDATION		$ 237,263		
	RECONCILED REVENUE REQUIREMENT				$ 196,058
	OTHER RECONCILING ITEMS				
	APS PROPOSED ENVIRONMENTAL CHARGE				(4,315)
	UNRECONCILED DIFFERENCE				(180)
SCH. A	REVENUE REQUIREMENT RECOMMENDATION				$ 191,563

(a) Staff understands that APS agrees to adjustment in principle as well as to the value of the issue
(b) Staff understands that APS agrees to adjustment in principle but value of issue may be dependent upon other Commission determinations (i.e., rate of return authorized)
(c) Staff understands that APS does not agree with some element of, if not entire, adjustment

EXHIBIT
S-2
admitted

Utilitech, Inc.'s Twentieth Set of Data Requests
To Arizona Public Service Company
Docket No. E-01345A-05-0816
Issued September 26, 2006

UTI 20-389 Reference Attachment Nos. DEB-1RB, DEB-2RB and DEB-3RB affixed to the rebuttal testimony of Mr. Donald Brandt. Please provide the following regarding the noted attachments:

a. Summary output of the actual forecasts underlying each attachment noted.
b. Summary out of the actual forecasts underlying Attachments DEB-1 and DEB-2 included with Mr. Brandt's direct testimony.
c. A listing of major input changes in forecasts for 2006 and 2007, as well related dollar impact, reflected in noted attachments to Mr. Brandt's rebuttal testimony that changed from forecasts underlying similar attachments included with Mr. Brandt's direct testimony.
d. Power-Supply-Adjustor ("PSA") includable costs included within each underlying forecast for each period before consideration of any deferral accounting
e. Any and all PSA deferrals forecasted for each period designed to capture the difference in PSA-includable costs being incurred versus PSA revenues being collected
f. Net PSA-includable expense recorded for each period (PSA-includable costs before deferral accounting less any PSA deferrals included within each forecast period.)
g. All PSA revenues included within each forecast for each period, broken into subcategories, as applicable (i.e., assumed PSA revenues expected to be collected following implementation of new PSA factor that considers forecasted 2007 PSA-includable costs, PSA factor at current 4 mil cap, paragraph 19 (d) surcharge amounts, etc.)
h. Provide a reconciliation of PSA-includable costs to PSA base plus all adjustor revenues for each period shown.
i. Calculations underlying the development of the various PSA factors used in each forecast period, tying amounts used in the PSA factors development back into forecasted amounts of PSA-includable costs reflected in each forecast period.
j. Describe and specifically quantify how Staff's recommendations regarding the disallowance of power supply costs stemming from the Palo Verde outages in 2005 have been reflected within each and every forecast period.
k. To the extent not specifically addressed in response to other subparts to this data request, please provide the amount, if any, of assumed disallowed or unrecovered PSA-includable costs for any reason for each period, explaining the reason for each assumed disallowance/under recovery.

l. Provide the actual calculation underlying each financial ratio shown, in hard copy as well as executable Excel format, tying starting point input numbers utilized in each calculation back to line items shown in the summary of forecasts being provided within subpart (a) to this request.

m. Provide the amount of FAS-87 derived pension expense and FAS 106-derived post retirement medical expense included within each forecast by period.

n. Provide the amount of amortization for accelerated recovery of the underfunded pension liability included within each forecast period (that would be consistent with APS' rate request in the current case).

o. Provide the amount of incentive compensation pay included within each forecast period. Distinguish by class/type of pay as applicable.

p. Provide the gross amount of unregulated marketing and trading revenues and *all* related expenses by category included in the forecast for each period.

RESPONSE:

a. See pages 1-3 of DEB_WP1RB, pages 1-3 of DEB_WP2RB, and pages 1-3 of DEB_WP3RB.

b. See pages 1-3 of DEB_WP23 and pages 1-3 of DEB_WP21.

c. See DEB_WP23 pages 1 through 3 for fuel and purchased power levels, O&M expense levels, construction expenditure levels, interest expense levels, and other expense levels from the original 21.3% Company asking financial forecast filed in January 2006.

See DEB_WP1RB pages 1 through 3 for fuel and purchased power levels, O&M expense levels, construction expenditure levels, interest expense levels, and other expense levels from the September 2006 21.2% Company asking rebuttal filing. The rebuttal filing includes updated information for O&M expense levels, construction expenditure levels, interest expense levels, and fuel and purchased power levels reflecting market prices from mid-2006. The principal change in the financial forecast between direct testimony in January and rebuttal testimony in September is the assumed timing of base rate relief. The January forecast assumed the 21.3% was effective January 1, 2007. The September forecast assumed the 21.2% is effective May 1, 2007.

d. Please see Attachment **APS12809**, line 7, for these amounts.

e. Please see Attachment **APS12809**, line 10, for these amounts.

f. Please see Response to Data Request UTI-20-388 (d) and (c).

g. Please see Attachment **APS12809**, lines 18, 26, and 31, for these amounts.

h. Such a reconciliation has not been prepared.

i. References in this response are to Attachment **APS12809**.

Annual Adjustor

This is calculated by summing the year end PSA Tracking Balance (line 14) and the year end Paragraph 19(d) Balance (less any amounts held in the Paragraph 19(d) account pending recovery proceedings) and dividing the sum(Year End Balance) by expected energy sales for the 12 months starting February of the following year. If this value(Adjustor Ratio) is less than or equal to 0.4000 ¢/kWh, then the entire year end PSA Tracking Balance moves into the Annual Adjustor Account (line 16) in January of the following year, and the Annual Adjustor (line 15) is set equal to the Adjustor Ratio. If the Adjustor Ratio is greater than 0.4000 ¢/kWh, then the Annual Adjustor is set to 0.4000 ¢/kWh. The Addition to the Annual Tracking Account (line 16) is set to equal the product of to 0.4000 ¢/kWh the expected energy sales for the 12 months starting February of the following year. The difference between the Year End Balance and this value moves into the Paragraph 19(d) account for recovery (with interest) in subsequent years.

Surcharge Rate

Upon recovery authorization by the Commission of certain amounts held in the Paragraph 19(d) Account, the recovery amount is transferred to the Surcharge Account from the Paragraph 19(d) account. (In the case of a final ruling on disallowance, the full amount in question is transferred out of the Paragraph 19(d) account, with the allowed recovery amount transferred to the Surcharge Account, and the disallowed amount written off by the Company.) The Surcharge Rate is calculated by dividing the transferred amount by the expected energy sales for the authorized recovery period.

Interim Adjustor
This is an additional collection that is authorized by the Commission. When it is in effect, the revenue collected offsets a transfer of equal magnitude from the Annual Tracking Account. No Balance is accrued in the Interim Adjustor Account.

Prospective Adjustor (DEB-2RB only)
This is calculated by dividing the Expected Monthly Fuel Deferrals for the 12 months beginning February by the expected energy sales for the same period. When it is in effect, the revenue collected offsets a transfer of equal magnitude from the Annual Tracking Account. No Balance is accrued in the Prospective Adjustor Account.

j. Please see linen 20 and 24 in Attachment **APS12809** relating to DEB-2RB. In May, 2007, the paragraph 19(d) Account is reduced by $44.6 million. $27.6 million is moved to the Surcharge Account to be recovered through a $0.0967 ¢/kWh surcharge effective from May 2007 through April 2008. The remainder is written off by APS.

k. In addition to the Palo Verde outage disallowance reflected in "j" above, APS is not recovering 10% of all fuel costs above the base rate due to the 90/10 sharing mechanism. This amounts to the following totals in each case:

$000	2007	2008
DEB-1RB APS case	4,530	621
DEB-2RB Staff case	7,962	336
DEB-3RB RUCO case	7,052	4,182

l. See pages 1-3 of DEB_WP1RB, pages 1-3 of DEB_WP2RB, pages 1-3 of DEB_WP3RB, pages 1-3 of DEB_WP23 and pages 1-3 of DEB_WP21.

m. The Company's forecast includes approximately $37 million of pension expense and $22 million of OPEB expense per year in O&M expense.

n. The forecast assumes $43.695 million of annual underfunded pension liability expense starting May 1, 2007 concurrent with the 21.2% base rate increase.

o. The Company budgets approximately $15m of O&M expense each year for incentive, which is $9m after income tax impacts. As each year comes to a close after December 31st, the $15m of O&M expense is adjusted up or down according to performance versus targets in the various incentive indicators.

p. The Company's forecast includes approximately $7 million of annual O&M expense for unregulated marketing and trading and a $3 million to $4 million average gross margin for unregulated marketing and trading. This is an average of approximately $2 million loss per year after income taxes, which has an insignificant impact on the Company's bond rating benchmarks. However, the unregulated marketing and trading revenues and expenses were removed from the Company's 9/30/05 test year.

Witness: Donald Brandt

EXHIBIT
S-3
Admitted

INITIAL DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY
SUBMITTED BY TECHNICAL ASSOCIATES, INC.
ON BEHALF OF THE ARIZONA CORPORATION COMMISSION STAFF
DOCKET NO. E-01345A-05-0816

TAI-1-13 RE: Flotation cost adjustment recommendation of 20 basis points. Please quantify the revenue requirement impact of Dr. Avera's flotation cost adjustment for APS, should the Commission approve it.

Response:

Dr. Avera's 20 basis point flotation cost adjustment is included in the Company's requested 11.5% cost of equity. The 20 basis point adjustment makes up $8 million of total revenue requirements.

20 Basis Point Increase in Cost of Equity	.20%
Common Equity Percentage of Cost of Capital	X 54.5%
Weighted Cost Difference	.109%
Rate Base	X 4,466,697
Earnings Requirement	4,869
Tax Gross-up	X 1.6407
Revenue Requirement ($000)	7,988

Witness: TBD

EXHIBIT NO. _____ (MKG-1T)
DOCKET NO._____
2001 PSE RATE CASE
WITNESS: MARK K. GORDON

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DIRECT TESTIMONY OF MARK K. GORDON
ON BEHALF OF PUGET SOUND ENERGY, INC.

NOVEMBER 26, 2001

EXHIBIT
S-4
admitted

PUGET SOUND ENERGY, INC.

DIRECT TESTIMONY OF MARK K. GORDON

I. INTRODUCTION

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

A: My name is Mark K. Gordon. My business address is One Embarcadero Center, Suite 1400, San Francisco, CA 94111-3703. I am a principal at Hewitt Associates LLC ("Hewitt").

Q: Would you describe your educational background, employment experience and current responsibilities?

A: My responsibilities and educational and employment experience are described in Exhibit MKG-2.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is:

- To explain the purpose, prevalence, costs and effectiveness of variable incentive pay in industry generally, and specifically at Puget Sound Energy, Inc. ("PSE").
- To explain how variable and incentive pay is designed to affect employee motivation, customer service, costs, efficiency and ultimately ratepayers.

Q: Would you please summarize your testimony?

A: Broad-based variable pay plans are used in over 80% of organizations today because the benefits (or performance outcomes) outweigh the program costs. They have taken on increasing importance in helping utilities provide a competitive "total compensation" package that allows them to compete with general industry companies to attract and retain a competent, stable workforce,

minimizing costs associated with high turnover, including recruiting, training, and "downtime." Variable incentive compensation helps ratepayers by managing the company's ongoing costs, as incentive awards must be "re-earned" every year as opposed to "fixed" base pay which becomes an ever increasing entitlement without any requirement for improved operating performance. Variable compensation can also benefit ratepayers by increasing levels of customer service, reliability, and the like, if designed to provide incentives for such improved efficiencies and benefits. PSE's employee incentive plan design is consistent with market practices and benefits ratepayers by creating employee incentives to control costs and increase efficiency, productivity, service and safety.

II. VARIABLE INCENTIVE PAY IN INDUSTRY

Q: Would you give an overview of the current role of variable incentive pay in American business?

A: Corporate America, including the utility and energy services industry, has undergone significant changes and restructuring over the past decade. Evolving business strategies, global competition, workforce demographics, and the competitive labor market are key factors driving companies to create flexible organization structures and human resource systems necessary for ongoing business success. One of the more subtle but sweeping changes in human resource strategy over this time period has been the widespread implementation of variable incentive compensation programs as an integral element of the total compensation and performance management systems. Increasingly, these systems, once reserved for senior management, are being extended to cover all employees.

A properly designed incentive program with a competitive award structure has become a critical strategy for retaining employees, recruiting new talent and

motivating desired performance. A company without an incentive compensation program today is at a competitive disadvantage.

Q: What are the reasons behind the use of variable incentive pay?

A: The philosophy and strategic reasons behind the introduction of variable incentive plans include:

- Linking pay with performance and personal contribution to results.
- Motivating participants to achieve higher levels of performance.
- Communicating and focusing on critical success measures.
- Reducing fixed costs including the direct, ongoing build-up of base salary and indirect costs of pay-related benefit programs (i.e., life insurance, time off, etc.).
- Reinforcing desired behaviors, as well as results.
- Reinforcing an employee ownership culture.

Q: What factors in an incentive pay plan affect whether the program will be effective?

A: While the majority of companies administer variable incentive programs, not all have been successful in changing behavior or improving performance results. Factors that increase the rate of success include:

- Setting realistic goals or targets.
- Effectively communicating plans.
- Using appropriate measures and tracking methods to measure progress.
- Ensuring a clear understanding of plan objectives.

In addition, motivation theory suggests that the effectiveness of an incentive plan must be driven by the employee's perception of the ability to impact performance results, the probability of achieving pre-set goals and the meaningfulness of rewards.

Q: What proportion of U.S. businesses, including energy services and utility companies, have variable incentive pay plans?

A: A recent Hewitt survey (2001/2002 Salary Increase Survey) of over 900 manufacturing and service companies (including 47 gas and electric utilities) shows that the prevalence of U.S. companies with at least one broad-based variable compensation plan has increased from 51% in 1991 to over 80% in 2001. The prevalence among utility organizations is consistent with the broader survey group. Since 1991, average company spending (as a percent of payroll) on broad-based variable pay for salaried exempt employees (below the executive level) has steadily increased over 250% from 3.8% to 10.8% of payroll. This has shifted pay from fixed base pay to variable pay, which is more closely tied to desired results. Over the same time period, average annual merit increase budgets have declined from 5% of payroll to between 4.0% and 4.5%. This inverse relationship demonstrates the increasing role variable pay has played in the total compensation mix shifting from "fixed pay" to "at risk" target pay for performance.

This trend is expected to continue in the foreseeable future as organizations continue to differentiate, recognize, and reward performance results year to year at the corporate, business unit, and individual levels.

III. PSE'S VARIABLE INCENTIVE PAY PLANS

Q: Have you reviewed PSE's variable incentive pay plans?

A: Yes.

Q: On what basis did you formulate your analysis of PSE's plans?

A: I have reviewed and analyzed each of PSE's current incentive pay plans. The analysis is based on Hewitt's collective resources and my knowledge and experience gained in consulting with numerous organizations including many utilities and energy services companies.

Q: What purposes are designed to be achieved by PSE's incentive plans?

A: PSE's incentive plans are intended to improve PSE's collective performance by helping employees focus on selected goals, motivating them to change their behaviors and rewarding them for performance achievement. PSE's broad-based incentive program is called the Goals and Incentives program because it combines identification of key goals and provides a monetary incentive when these goals are accomplished. All employees participate in the plan from bargaining unit to the officer level. PSE's Goals and Incentives program is designed to communicate to employees specific, attainable yet challenging goals. PSE has defined key business goals to include improving employee productivity, operational efficiency, safety and customer satisfaction. The incentive program is an integral part of an overall business strategy that PSE has adopted to be the "Best Distribution Company" in the energy services industry, as measured by quality customer service and low costs to customers.

Q: Would you please explain how the incentive goals are established for PSE employees?

A: Employees are encouraged to propose goals each year to PSE's management. Goals must be measurable, results-oriented, and clearly stated so employees have a clear "line-of-sight" for how their personal work affects whether a particular goal was achieved. After being developed by employees and proposed to their managers and supervisors, goals are reviewed and edited by directors, and then submitted to the Company's officers for final selection and development.

Employee groups are then assigned specific goals, including goals contributing to efficiency, safety, customer service and cost control. The employee group assigned to a particular goal then determines how to go about achieving the goal and develops an implementation plan.

Q: Would you describe the incentive award goals that apply generally to PSE employees?

A: Each employee has a combination of corporate, business unit and team goals, which are weighted based on organization level and job function. All employee incentive awards are tied in part to the successful achievement of the ten Service Quality Indices ("SQIs") established with the Commission and to the cost-effective operation of the Company.

As an example, PSE's goals include electric and gas emergency response metrics, targeted outage reductions and a variety of customer service metrics such as IT service levels, customer billings and call center performance, all of which are related to broader Company SQIs. The goals are designed so that cost containment initiatives cannot be achieved by compromising customer service and reliability. The final awards for financial goals are reduced 10% for each of the ten SQI goals established with the WUTC that are not met. For example, if only six of the ten SQIs are achieved, any payout of the corporate and business unit financial goals would be reduced by 40%. PSE sets threshold, target and superior levels of performance goals that are tough, but achievable. To motivate this level of operating performance, PSE provides meaningful award opportunities at competitive market levels and "upside" opportunities for superior performance levels.

Q: How do incentives apply for PSE employees who are subject to collective bargaining agreements?

A: All employees at PSE are eligible to participate in the Goals and Incentives program. Employees subject to collective bargaining agreements have a similar set of objectives as other non-exempt and exempt employees who are not covered by bargaining agreements. The primary difference for represented employees is

that the target award opportunities are expressed as a fixed dollar amount and are equal for all members of a bargaining group. Non-represented employees have their target awards expressed as a percentage of base pay. Otherwise, the administration of the program is the same for all employees.

Q: How is PSE's incentive plan at the officer and director level structured?

A: Officers and directors participate in the same program as all other employees. At this level, a higher portion of incentives is weighted based on earnings per share results. However, the "funded award" based on earnings per share is reduced 10% for each of the ten SQI goals established with the WUTC that are not met. This balanced structure emphasizes the need both for financial success and for delivering operating results that are in the customers' interest.

Q: How does PSE's plan compare with other companies in the industry?

A: PSE's Goals and Incentive program is more detailed in the specificity of financial and non-financial goals and better communicates the linkage of goal attainment with incentive award opportunity than the majority of broad-based incentive plans at other companies. Very often, broad-based incentive plans are solely tied to company earnings with no variation for business unit or team performance, and no link to customer service and/or service reliability objectives. These types of plans act more as an end of year "bonus" than a motivational "pay for performance" system driving specified behavior.

Q: Does PSE have a long term incentive plan?

A: Yes, PSE does provide an equity-based long-term incentive plan using common shares of Puget Energy stock. PSE administers a long-term incentive plan for its officers and directors, in the form of a performance share plan. Based on the current structure of this plan, awards under this plan are fully funded by shareholders and not included in the rate base.

Long-term incentives have been the fastest growing component of executive compensation over the last ten years. Today, long-term incentive awards account for approximately one-third of officer pay and are integral to a company's ability to attract and retain management personnel. Under this performance plan, participants are granted a "target" number of shares with a grant value that is market competitive (approximately at the competitive median). Awards are earned based on the Company's cumulative total shareholder return (stock price changes plus dividends) over a four-year period relative to a peer group of gas and electric utility companies. Threshold, target, and superior achievement goals are set before the start of a given performance cycle. Performance requirements are aggressively set such that if relative performance is below the 35th percentile, no awards are earned and TSR performance must be at the 55th percentile (i.e., performance has to be better than 55% of peer organizations) to vest in 100% of the target grant.

Q: How do PSE's incentive plans help ratepayers?

A: Incentive plans have taken on increasing importance in helping utilities provide a competitive "total compensation" package that allows them to compete with general industry companies to attract and retain a competent, stable workforce. As job mobility across industries and the heightened competition for talent has increased in recent years, workforce stability and retention throughout the employee ranks provide several benefits to ratepayers. By retaining well-performing employees, ratepayers benefit not only from the heightened experience of these valued employees but also by minimizing turnover costs arising from recruiting, "downtime" and retraining. In addition, variable incentive compensation helps to manage payroll costs because incentive awards must be "re-earned" every year, unlike traditional base pay which tends to increase every

year without directly requiring a corresponding increase in performance. Moreover, well-performing employees who meet these goals are rewarded with incentive pay which tends to increase employee retention and ongoing contributions.

Incentive plans are undertaken because the benefits (or performance outcomes) will outweigh the program costs. PSE's pay-for-performance system is designed to increase worker productivity, customer service, cost control, safety and efficiency. All of these goals contribute to two common results: 1) reducing costs, which can then be passed along to ratepayers in the form of reduced rates or which can free up revenues for other investments to benefit ratepayers and 2) provide higher levels of customer service or to limit borrowing.

The long term incentive plan also benefits PSE's ratepayers, even though the performance measure in the long-term incentive plan is focused on shareholder value, by:

- Minimizing costs associated with high turnover, including recruiting, training, and "downtime" associated with filling vacant positions;
- Minimizing the need for additional base pay or annual cash incentive awards to provide "total" competitive pay opportunities; and
- Providing continuity of the management team to develop and implement effective business strategies that span multiple year periods.

IV. PSE INCENTIVE PLAN RESULTS

Q: How is PSE's incentive pay plan funded and allocated?

A: PSE's incentive awards are funded and allocated based on a combination of financial and non-financial operating results. In 2001, Officer and Director target awards represent less than 20% of the total budgeted annual employee incentive pool. Awards at this organizational level are primarily "funded" based on

earnings performance. However, as described above, the final award pool is reduced incrementally 10% if threshold performance levels are not achieved on ten distinct customer service quality indices. This performance and award structure is designed to balance the focus on ratepayers and shareholders.

Incentive awards for employees below the officer and director level are more directly tied to the achievement of business unit and functional operating performance goals (less than 30% of these awards are directly funded by corporate earnings per share results, and that 30% is modified by SQI performance).

PSE employees are told that they will receive a "target" award if future actual results equal those desired. Actual payments are based on results achieved. They are usually below target amounts if the overall performance has not met target objectives, and above target amounts if performance exceeds target performance objectives. The level of goals achieved in one year often provides the minimum funding threshold for similar goals the following year, encouraging continuous improvement. In Exhibit MKG-3, I have provided a graph entitled "PSE Current Target and Most Recent Actual Incentive Awards." This Exhibit shows PSE's actual awards earned (based on results achieved in its incentive plan) compared to PSE's target award opportunities this past year. As demonstrated in Exhibit MKG-3, incentive pay has become a significant ongoing component to competitive annual cash compensation practices at all PSE's organization levels, averaging 9.8% for all employees.

Q: How does the cost of PSE's plans compare with other similarly situated companies?

A: PSE's target and actual awards are comparable to opportunity and actual pay at other companies. As the prevalence of variable incentive pay programs has

increased in recent years, so have the target (budgeted) and actual awards at each PSE organization level. The PSE payouts under its program are consistent with the Hewitt survey, which reported average payout levels at 10.8% of payroll for salaried exempt employees and 4.5% to 6% for bargaining unit and hourly employees. For further comparison, the table entitled "Utility vs. Industry Comparison" in Exhibit MKG-4 (results of Hewitt's 2001 Total Compensation Measurement DataBase™) summarizes the average range of target and actual annual business incentive awards (expressed as a percentage of base pay) at three organization participant levels: Director and Officer, Other Exempt, and Nonexempt employees. Again, PSE's most recent target awards (expressed as a percentage of base pay) shown in Exhibit MKG-3 vary from 10% for non-exempt employees to 30% of base pay for Director level and above. This compares with the utility and industry median (i.e., 50th percentile) target opportunity found in Exhibit MKG-4, ranging from 8% for non-exempt to 30% for Director level and above. Overall, PSE's actual awards paid in 2001 exceeded target levels based on performance results. Similarly, in the industry comparisons, actual awards at the 75th percentile exceeded target for the plan year.

Q: Does PSE's incentive pay plan correlate with PSE's overall performance?

A: As described in the testimony of John Shearman, PSE has achieved operation and maintenance costs that are among the lowest in the nation and system safety and service reliability performance trends that are better than the industry average. In my opinion, PSE's annual variable goals and incentive pay program has been a significant contribution to PSE's ability to achieve such results since its introduction in 1998.

Q: Based on your analysis, what conclusions have you drawn about PSE's variable incentive compensation program?

A: PSE's variable incentive compensation program is consistent with market practices and effective at aligning employees with its business mission to be the "Best Distribution Company." The design and administration of the programs appears to correlate with results that benefit PSE's ratepayers. Its commitment to goal setting at all levels of the organization, establishment of "stretch" goals, and ongoing communication serve to motivate employees and create a clear focus on accountability. In sum, PSE's program motivates employee performance, aligns employee behavior with company goals, and helps to attract and retain employees, all of which are critical to the success of a high-performance and efficient energy distribution company in today's competitive business environment.

Q: Does this conclude your testimony?

A: Yes.

[BA013150017]

EXHIBIT NO. _____ (MKG-2)
DOCKET NO._____
2001 PSE RATE CASE
WITNESS: MARK K. GORDON

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

PROFESSIONAL QUALIFICATIONS OF MARK K. GORDON
ON BEHALF OF PUGET SOUND ENERGY, INC.

PUGET SOUND ENERGY, INC.

PROFESSIONAL QUALIFICATIONS OF MARK K. GORDON

Q: Would you describe your employment experience?

A: I work with a broad range of public and private general industry corporations including utility and energy service businesses in the Western United States. I have over fifteen years of management consulting experience with Hewitt, specializing in executive and broad-based compensation program strategy, design and implementation.

Q: What does Hewitt do?

A: Hewitt is a global management consulting and outsourcing firm specializing in human resources solutions. With more than 12,000 associates working in 37 countries worldwide, our client roster includes more than two-thirds of the Fortune 500 and more than a third of the Global 500. Since 1940, Hewitt has provided thousands of organizations, including numerous electric and gas utilities and energy services companies, with a broad range of services related to employee compensation. Our compensation consulting services include setting rewards strategy, competitive market analysis using a library of published, private and proprietary survey sources, incentive design and communications.

Q: Would you describe your educational background?

A: I have a Bachelor's degree in Psychology and a Master's degree in Business Administration from the University of California at Berkeley.

[BA013150017]

PSE's Current Target and Most Recent Actual Average Incentive Awards

Level	PSE Target Award Opportunity in 2001 (% of base pay)	PSE Actual Award Earned for 2000 Performance (% of base pay paid in 2001)
Officer & Director	30.1%	40.4%
Other Exempt	10.0%	13.5%
Non-Exempt	10.0%	10.9%
Represented	4.4%	4.0%
All Employees	8.2%	9.8%

Utility vs General Industry Comparison
Current Target and Most Recent Actual Incentive Awards

Level	Utility Target Award Opportunity in 2001 (% of base pay)		General Industry Target Award Opportunity in 2001 (% of base pay)	
	50th Percentile*	75th Percentile**	50th Percentile	75th Percentile
Officer & Director***	30%	35%	34%	35%
Other Exempt	9%	10%	11%	15%
Non-Exempt	8%	10%	9%	10%

Level	Utility Actual Award Paid for 2000 Performance (% of base pay paid in 2001)		General Industry Actual Award Paid for 2000 Performance (% of base pay paid in 2001)	
	50th Percentile	75th Percentile	50th Percentile	75th Percentile
Officer & Director	33%	46%	32%	42%
Other Exempt	8%	15%	8%	12%
Non-Exempt	8%	10%	5%	7%

*50th Percentile means 50% of the companies pay more or less than this amount (median).
**75th Percentile means 75% of organizations pay below this amount.
***Officer target awards range from 20% of base pay at the VP level to 60% or more for the CEO.

Arizona Public Company
Estimated Revenue Requirement by Project **($000s)**
Assumes no rate cases over the 2007-2011 time frame. No rate-basing of environmental projects.
Factor effective Jan. 2007, then updated July starting 2008 and in subsequent Julys.

	Calendar 2007 Requirement	Calendar 2008 Requirement	Calendar 2009 Requirement	Calendar 2010 Requirement	Calendar 2011 Requirement
EIC 1 Cholla Unit 1 Baghouse	2,659	4,365	4,230	4,396	4,232
EIC 2 Cholla Unit 1 Low NOX Burner	364	796	767	802	768
EIC 3 Cholla Unit 1 Scrubber Upgrade	430	1,001	969	1,008	969
EIC 4 Cholla Unit 2 Low NOX Burner	109	506	996	960	1,002
EIC 5 Cholla Unit 3 Low NOX Burner	-	121	458	872	841
EIC 6 Cholla Unit 3 Baghouse	895	3,426	6,147	10,130	9,799
EIC 7 Cholla Unit 3 Scrubber	1,376	4,361	6,928	14,575	14,218
EIC 8 Cholla Lime Slaking Upgrade	720	1,286	1,738	1,676	1,749
EIC 9 Cholla Slurry Disposal	151	330	495	477	498
EIC 10 Cholla Unit 1 Carbon Injection	-	41	133	534	525
EIC 11 Cholla Unit 3 Carbon Injection	-	69	266	1,196	1,179
EIC 12 Cholla Unit 2 Baghouse	-	48	1,014	3,840	6,833
EIC 13 Cholla Unit 2 Carbon Injection	-	-	-	199	377
Total Revenue Requirement $(000)	6,705	16,349	24,141	40,667	42,990
	18 Months 1/1/07-6/30/08	**12 Months 7/1/08-6/30/09**	**12 Months 7/1/09-6/30/10**	**12 Months 7/1/10-6/30/11**	**12 Months 7/1/11-6/30/12**
Retail Energy - MWH	41,815,908	30,146,538	31,287,637	32,395,924	33,449,006
Estimated EIC/Kwh Rate	0.000160354	0.000542324	0.000771584	0.001255306	0.001285225
Estimated EIC/Kwh Rate rounded to six decimal places	0.00016	0.000542	0.000772	0.001255	0.001285

Annual Resulting Revenue Increase

	Calendar 2007
Forecasted Total 12 Months MWH	28,388,822
Estimated Total 12 Months. EIC Retail Revenue $(000)	4,542
Estimated Total Company Retail Revenue $(000)	2,347,077
Resulting Revenue Increase (%)	**0.194%**

EXHIBIT
S-5
Admitted

EXHIBIT
S-6
Admitted

TOWERS
PERRIN
HR SERVICES

Pinnacle West Capital Corporation

Actuarial Valuation Reports

Retirement Plans 2006

October 2006

This report is confidential and intended solely for the information and benefit of the immediate recipient thereof. It may not be distributed to a third party unless expressly allowed under the "Actuarial Certification, Reliances and Distribution" section herein.

Pinnacle West Capital Corporation Retirement Plan

Actuarial Valuation Report

Pension Cost for Fiscal Year Ending December 31, 2006

Employer Contributions for Plan Year Beginning January 1, 2006

October 2006

This report is confidential and intended solely for the information and benefit of the immediate recipient thereof. It may not be distributed to a third party unless expressly allowed under the "Actuarial Certification, Reliances and Distribution" section herein.

TOWERS
PERRIN
HR SERVICES

Pension Cost

	Fiscal 2006	Fiscal 2005
Pension Cost		
Service cost	$ 45,627,349	$ 43,110,183
Interest cost	85,722,513	81,274,630
Expected return on assets	(95,911,900)	(88,402,837)
Amortization:		
▸ Transition obligation (asset)	(645,428)	(3,227,088)
▸ Prior service cost (credit)	2,255,875	2,255,875
▸ Net loss (gain)	19,316,646	16,151,203
Pension cost	$ 56,365,055	$ 51,161,966
Percent of covered pay	11.5%	11.1%
Per active participant	$ 7,965	$ 7,489

Change in Pension Cost	
Pension cost for fiscal 2005	$ 51,161,966
Change from fiscal 2005 to fiscal 2006:	
▸ Expected based on prior valuation	(1,676,204)
▸ Loss (gain) from noninvestment experience	768,073
▸ Loss (gain) from asset experience	2,559,664
▸ Assumption changes	3,551,556
▸ Plan amendments	0
Pension cost for fiscal 2006	$ 56,365,055

Selected Financial Statement Disclosure Information

The following information was included in Pinnacle West's 2005 pension disclosures. This information was developed by adjusting the prior year's valuation results for the passage of time and other significant changes.

	Fiscal 2005	Fiscal 2004
Change in Benefit Obligation		
PBO, beginning of year	$ 1,372,198,664	$ 1,232,123,226
Service cost	43,110,183	39,905,053
Interest cost	81,274,630	77,286,699
Plan amendments	0	0
Actuarial loss (gain)	30,131,478	65,741,930
Benefits paid	(43,431,972)	(42,858,244)
Curtailments, settlements, and termination benefits	0	0
PBO, end of year	$ 1,483,282,983	$ 1,372,198,664
Change in Plan Assets		
Fair value of plan assets, beginning of year	$ 982,282,105	$ 887,310,879
Actual return on plan assets	73,297,976	102,829,470
Employer contributions	52,700,000	35,000,000
Participant contributions	0	0
Benefits paid	(43,431,972)	(42,858,244)
Settlements	0	0
Fair value of plan assets, end of year	$ 1,064,848,109	$ 982,282,105

The accumulated benefit obligation was $1,145.9 million and $1,241.8 million at December 31, 2004 and December 31, 2005, respectively.

The following information was also included in Pinnacle West's pension disclosures.

	December 31, 2006	December 31, 2005
Reconciliation of Funded Status		
Funded status	$ (418,434,874)	$ (389,916,559)
Unrecognized net actuarial loss (gain)	372,524,312	343,439,176
Unrecognized prior service cost (credit)	11,510,524	13,766,399
Unrecognized transition obligation (asset)	(645,428)	(3,872,516)
Prepaid (accrued) pension cost	$ (35,045,466)	$ (36,583,500)
Amount Recognized in Statement of Financial Position		
Prepaid pension cost	$ 0	$ 0
Accrued pension cost	(35,045,466)	(36,583,500)
Additional minimum liability	(141,938,404)	(127,080,144)
Intangible asset	11,510,524	13,766,399
Accumulated other comprehensive income	130,427,880	113,313,745
Net amount recognized	$ (35,045,466)	$ (36,583,500)

The accumulated other comprehensive income has not been tax effected. Any tax effect would have been separately recognized.

EXHIBIT
S-7
admitted

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATER 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 TO AMEND DECISION NO. 67744	)	DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY AND

ATTACHMENTS OF

MICHAEL L. BROSCH

ON BEHALF OF THE
UTILITIES DIVISION STAFF

AUGUST 18, 2006

DIRECT TESTIMONY
OF
MICHAEL L. BROSCH

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

Q. Please state your name and address.

A. My name is Michael L. Brosch. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. Where are you employed and in what capacity?

A. I am a principal in the firm Utilitech, Inc., a consulting firm engaged primarily in utility rate and regulation work. The firm's business and my responsibilities are related to special services work for utility regulatory clients. These services include rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses and focused investigations related to utility operations and ratemaking issues.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff of the Arizona Corporation Commission ("Staff"). Utilitech entered into a contract with the Staff to review and respond to the rate case filing of Arizona Public Service Company ("APS" or "Company"). Utilitech's direct responsibilities generally relate to the development and presentation of the Staff's positions regarding APS's test period revenue requirement and cost of service allocations. Utilitech

has employed sub-contractors in two areas. Liberty Consulting Group, Inc. is responsible for analyzing and presenting Staff's evidence regarding APS fuel and purchased power expenses and the related Fuel Adjustment Clause issues and this work is addressed in the Direct Testimony of Mr. John Antonuk. Technical Associates, Inc. also served as sub-contractor to Utilitech and Mr. David Parcell is sponsoring Staff's cost of capital evidence. Additionally, the ACC Staff is internally addressing some issue areas, including rate design, Demand Side Management Programs, Environmental Portfolio Standards, and quality of service issues.

Q. What is the purpose of your testimony in this Cause?

A. My testimony is intended to describe and sponsor, on behalf of Staff, class cost of service evidence based upon Staff's calculated revenue requirement and appropriate cost allocation methodologies.

QUALIFICATIONS

Q. Will you summarize your educational background and professional experience in the field of utility regulation?

A. I graduated from the University of Missouri, Kansas City, in 1978 with a Bachelor of Business Administration Degree, majoring in accounting. I hold a CPA Certificate in the State of Missouri and in the State of Kansas. I am a member of the American Institute of Certified Public Accountants, the Missouri Society of Certified Public Accountants, and the Kansas Society of Certified

Public Accountants. Since completion of formal education, my entire professional career has been dedicated to utility operations and regulation consulting.

From 1978 to 1981, I served as a public utility accountant with the Staff of the Missouri Public Service Commission. While employed by the Missouri Commission, I participated in rate case examinations involving electric, gas, water, steam, transit, and telephone utilities operating in Missouri. In December 1981, I accepted employment with Troupe Kehoe Whiteaker & Kent, a Kansas City CPA firm, in its public utility department. While with Troupe Kehoe Whiteaker & Kent, I was involved in the review, analysis, and presentation of a wide range of utility rate case issues and various other utility management advisory functions for both utility company and regulatory agency clients. In May 1983, I commenced employment with Lubow, McKay, Stevens and Lewis, an accounting and public utility consulting firm. While employed by that firm, I was involved in numerous regulatory proceedings and directed work related to various special projects.

In June 1985, Dittmer, Brosch and Associates, Inc. (the predecessor firm to Utilitech, Inc.) was organized. The firm specializes in public utility regulatory and management consulting in the electric, gas, telecommunications, water, and waste water industries. As a principal of the firm, I am responsible for the supervision and conduct of the firm's various regulatory projects. A majority of the firm's business involves representation of utility commission

staff and consumer advocate interveners in utility rate proceedings and special or focused investigations.

I have testified before utility regulatory agencies in Arizona, Arkansas, California, Florida, Hawaii, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, Nevada, New Mexico, Ohio, Oklahoma, Utah, Washington and Wisconsin in numerous regulatory proceedings involving electric, gas, telephone, water, sewer, transit, and steam utilities. Attachment MLB-1 to this testimony sets forth additional details regarding my qualifications.

Q. Have you previously participated in Arizona Public Service Company rate case proceedings before this Commission?

A. Yes. Mr. Dittmer and I worked together in preparing the Staff's revenue requirement position in the most recent APS Arizona rate case, Docket No. E-01345A-03-0437. Mr. Dittmer and I were also Staff's revenue requirement consultants in two prior APS rate cases, Docket Nos. U-1435-85-367 and U-1345-90-007. I have also been involved in many rate cases and other dockets before the Commission involving utilities other than APS. A table listing my formal testimony filings is contained within Attachment MLB-2.

COST OF SERVICE ALLOCATION

Q. Why are cost of service allocation studies ("Cost of Service Studies" or "COSS") required in APS electric rate cases?

A. Cost of Service Studies are required for several purposes. First, it is necessary to perform jurisdictional allocations to segregate the retail portion of APS rate base and operating income that is subject to the jurisdiction of the Arizona Corporation Commission from that which is under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Then, these ACC-retail jurisdictional rate base and operating income elements are used to determine overall retail revenue requirements and are further allocated among retail customer classes using class cost of service allocations, so as to provide information reflective of the estimated cost to serve each customer class. The resulting class rates of return are often used as a guide for use in determining how the overall retail revenue change should be "spread" among customer classes. Class COSS results are also unbundled into functional and unit costs for each customer class as a guide in the design of tariff rate schedules.

Q. Has the Company prepared a test period COSS for these purposes?

A. Yes. APS actually conducted its COSS on a combined basis, performing jurisdictional and class allocations within a single spreadsheet-based model. The results of this work are sponsored by APS witness Mr. David Rumolo in a series of Schedules within the Company's filing identified as Schedules G-1 through G-7. At a summary level, APS Schedule G-1 indicates that the

Residential class Rate of Return at present rate levels (before any rate increase) of 1.52 percent on Rate Base is lower than the average return being earned by the entire ACC jurisdictional business of 2.59 percent. Other classes, such as General Service, Water Pumping and Dusk to Dawn (lighting), are shown to be earning above-average rates of return under present rates. All of these values are based upon the APS asserted revenue requirement before any rate increase.

Comparable results from the Company's COSS are shown on Schedule G-2 at "Proposed" rate levels, indicating how the class returns compare to the overall "Total ACC Jurisdiction" column of data if the entire rate increase proposed by APS is granted and implemented with the rate design proposed by the Company. Schedule G-1 shows the entire ACC Jurisdiction earning the Company's proposed 8.73 percent return on rate base, with comparable return levels from the other rate classes as shown in row 7.

Q. Is there only one single correct methodology that must be employed in the conduct of COSS studies?

A. No. There are generally accepted methods for the conduct of such studies that have been developed over many years of practice. For example, all COSS studies require that utility costs be separated by function, classified into three broad categories of cost causation (demand, energy and customer) and then allocated using reasonable data to estimate test year allocation factors. However, performing the COSS study requires judgment on the part of the analyst, particularly when determining specific cost classifications and in

selecting and applying allocation factors. Because of this unavoidable judgment element in the COSS process, it is not unusual for there to be differences of opinion among analysts. The element of judgment also causes regulators to often view the results of COSS to be useful as a guide in formulating utility rate design, rather than an absolute and accurate indicator of reasonable rates.

Q. Have you reviewed the jurisdictional and class cost of service allocations performed by APS witness Mr. Rumolo, as summarized in Section G of the Company's filing and in Mr. Rumolo's workpapers DJR_WP-1 through DJR_WP-5?

A. Yes. After reviewing the numerous electronic spreadsheet models and detailed workpapers supporting the test period jurisdictional and class cost allocations, I interviewed Mr. Rumolo and conducted discovery to validate input data and to test allocation logic.

Q. Does the APS COSS model produce reasonable results that can be used to accurately determine jurisdictional revenue requirements as well as class cost of service guidance?

A. I found the allocations performed by Mr. Rumolo to generally be reasonable and comparable to the allocation methodologies previously employed in APS general rate case proceedings. In fact, my only objection to the Company's approach is the same objection raised by Staff and RUCO in the Company's last rate case. The Company's study uses a Four Coincident Peak ("4CP")

allocation factor to allocate production demand costs, which are the costs associated with the Company's nuclear, coal and gas-fired generation facilities. Staff continues to believe that the Company's cost of service study should utilize an energy-weighted allocation approach, rather than allocating production demand costs based solely upon relative class demands registered during the four peak hours of the year. To correct this problem, I have modified the company's COSS to employ a 4 Coincident Peak (CP) and Average (4CP&Average) allocation approach for production plant investment and expenses for class cost of service allocations.

Q. What is the difference between using only coincident peak demand levels, such as the APS 4CP allocation approach, rather than using a combination of coincident peak and average demand levels?

A. Coincident peak demands are the measured maximum combined loads of all customers on the system, in the single hour (or 4 hours) when overall system demands are the highest during the year. The 4CP allocation factor would use these hourly demands registered by each customer class during the 4 highest peak system demand hours in test year to allocate cost responsibility for all power generation production resources among classes. Customer usage during the other 8,756 hours of the year would have no impact upon the allocation of APS power plants under the 4CP approach. The theoretical basis for the 4CP approach is that meeting hourly peak demand is the sole planning criteria used

by APS that causes the Company to incur power generation facilities fixed costs.

In contrast, Staff does not accept the premise that the costs of APS power production facilities are incurred solely to meet peak hour demands, but are also incurred to efficiently produce electricity throughout the entire year. Staff therefore proposes that hourly peak demands should be heavily weighted in determining a production demand allocation factor, but that some weight should also be applied to customer demands throughout the rest of the year. Average demands are calculated by dividing total energy produced throughout the year by 8,760 annual hours to see how intensely power production resources are loaded throughout the year. To consider both peak demand levels and average demand levels, an energy-weighted allocation approach is often used by regulators, combining peak demands with average demands into a single allocation factor applicable to electric production facilities fixed costs.

Q. Have you prepared any Exhibits to quantify the changes to the Company's COSS that you sponsor?

A. Yes. Attachment MLB-3 to my testimony contains a series of Schedules that were prepared in the format of Mr. Rumolo's Workpaper DJR_WP1 and that incorporate Staff's revenue requirement accounting inputs along with COSS allocations performed using a 4CP & Average allocation of production demand costs. These calculations reflect all ratemaking adjustments that are being

proposed by Staff witnesses, before any rate increases that may result from this Docket.

For comparison to Staff's recommended COSS allocations performed on a 4CP & Average basis, my Attachment MLB-4 was prepared indicating how Staff's revenue requirement case would roll through the COSS allocations under the APS proposed 4CP methodology. Generally, the effect of using an energy-weighted 4CP & Average approach is to attribute some generating capacity costs to the lighting classes, unlike under the 4CP approach, and to attribute somewhat more production cost responsibility to the higher load factor customers that use more energy relative to their peak demands. These results can be seen by comparing the "Rate of Return Present" results at row 39 of Attachment MLB-3 under the 4CP & Average approach to the comparable amounts appearing on the same row of Attachment MLB-4.

Q. Have you provided Staff witness Ms. Andreasen with the COSS model so that she can consider class allocated accounting costs in the design of rates for APS?

A. Yes.

Q. Turning back to the production demand allocation issue that exists between APS and Staff, how significant is the selection of an appropriate allocation factor for demand-related production costs?

A. The single most controversial COSS allocation within a base rate proceeding for electric utilities is typically the production demand allocation factor, because

this factor is used to allocate a large percentage of non-fuel related expenses and all of the generating plant investment within rate base. For APS, production-demand classified costs are nearly half of total rate base and production-demand classified expenses total more than $570 million.[1]

Q. How does Mr. Rumolo explain his use of a 4CP allocation methodology for Production-Demand costs?

A. At page 7 of his testimony, Mr. Rumolo states, "Production-related and Transmission-related assets, and their associated costs, are generally designed and built to enable the Company to meet its system peak load. Therefore, they are allocated on the basis of the average of the system peak demands occurring in the months of June, July, August, and September ("4CP")."

Q. Do you dispute that APS designs and builds its production facilities to meet its system peak loads, as stated by Mr. Rumolo?

A. I dispute the notion that meeting peak demands in the summer months is the <u>sole</u> design criteria used by APS when it decides how to optimize its investment in electric production plant and how to operate and maintain generating resources. Even though APS is a summer peaking utility, it should be recognized that its generation facilities are required to serve customers during all of the non-peak hours of the year. Many of the costs incurred by APS to own, operate and maintain its power plants could be much lower if the

[1] APS Schedule G-3, column A, row 6 shows Production-Demand rate base of $2.1 billion, relative to total ACC rate base in column E, row 18 of $4.5 billion. Production-Demand classified expenses of $573 million are shown in APS Schedule G-4 at column A, row 6.

Company were concerned only with meeting demands during the four peak hours of the year.

For instance, rather than building expensive base load nuclear and coal-fired generating plants that run throughout the year at lower fuel expenses, APS theoretically could use much cheaper gas-fired peaking units throughout its generation fleet if its sole design criteria was meeting peak summer demands (without regard to energy costs). Additionally, APS could avoid significant operations expenses for its generating units if the units only needed to be available during the summer peak months and plant operations staff were not needed the other eight months. Production maintenance expenses could also be lower if generating unit available during the eight non-summer months was not a concern in the scheduling of unit overhauls. Thus, it is obvious that cost causation for APS production facilities goes beyond simply the need to meet peak demands in the summer.

Q. Under the APS-proposed 4CP approach, are there any customer classes that receive no allocation of demand-related costs for electric production facilities?

A. Yes. The Company-proposed 4CP allocation of production demand costs results in the Street Lighting and Dusk to Dawn lighting classes paying nothing toward the fixed costs of APS electric production facilities. This can be observed in at Schedule G-3 with respect to allocated Rate Base, in column A at Line Nos. 4 and 5, and at Schedule G-4, column A, Line Nos. 4 and 5 for Production Demand Operating Expenses. While it is obvious that APS must

use its electric generating facilities to serve these lighting customers, the fact that lighting loads do not occur coincident with the four hours when 4CP demands are measured causes customers in these classes to be allocated no production demand-related cost responsibility under the Company's approach.

Q. How does an energy-weighted allocation factor consider the fact that electric production facilities are designed and operated to efficiently meet both peak demands as well as demands throughout the other 8,756 hours of the year?

A. The 4CP and Average approach involves a weighted combination of the peak demand allocation factor used by APS, together with an average demand (or energy-based) allocation factor. Average demand for this purpose is based upon test period energy volumes divided by the total 8,760 hours throughout the year. The combination occurs by weighting the 4CP and the average demand statistics, by the sum of the combined peak demand plus the average demand. For APS, the factor used by Staff combined Mr. Rumolo's 4CP demand data weighted 65 percent, with average demand levels weighted 35 percent.

Q. Do any published authorities recognize energy-weighted allocation methods to be appropriately reflective of cost causation for electric utility production plant and O&M costs?

A. Yes. According to the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC"), at page 49:

> There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption.

This publication illustrates and explains many different energy weighting methods that are widely used to allocate production plant costs with a conclusion at page 67:

> This review of production cost allocation methods may not contain every method, but it is hoped that the reader will agree that the broad outlines of all methods are here. The possibilities for varying the methods are numerous and should suit the analysts' assessment of allocation objectives. Keep in mind that no method is prescribed by regulators to be followed exactly; an agreed upon method can be revised to reflect new technology, new rate design objectives, new information or a new analyst with new ideas. These methods are laid out here to reveal their flexibility; they can be seen as maps and the road you take is the one that best suits you.

The point to be drawn from the NARUC Manual is that considerable judgment is involved in the selection and application of COSS allocations, particular with respect to costs that do not fall cleanly into a "demand" or "energy" classification. In my judgment, use of an energy weighted 4CP and Average production allocation approach is necessary for APS to reflect cost causation for production plant investment and is also reasonable for expenses because generating capacity non-fuel O&M costs are incurred both to meet peak demand and to minimize fuel and operating costs. A straight 4CP peak demand-based allocation approach completely ignores the notion of fuel and O&M cost avoidance as an important element of production capacity cost causation.

Q. Do differences in the installed costs of APS base-load generating units, compared to costs of peaking facilities, support the use of an energy-weighted allocation factor for such facilities?

A. Yes. If the sole planning criteria in the selection of power plant technologies was to meet system peak demands for only a few coincident peak hours of the year, the utility would install only relatively inexpensive peaking generation, so as to minimize fixed costs of the facilities without much regard for fuel and operating expenses during only these few hours of use. Clearly, the facts illustrate that this is not what APS has done – where a blend of more expensive base load generation is combined with peaking units to efficiently meet demands throughout the year.

Using information from the APS 2005 FERC Form 1 report at pages 403.2 and 403.3, a comparison of Palo Verde base-load nuclear unit installed costs per KW and operating expense per KWH to similar data for the West Phoenix gas-fired combustion turbine units produces the following information:

Unit Cost Information	Palo Verde Nuclear	West Phoenix CT
Kind of Plant	Nuclear Base Load	Combustion Turbine
Installed Capacity KW	1,225,000	106,000
Cost per Installed KW	$2,085	$162
Expense per KW - 2005	$0.0230	$0.2314

While an analyst might select different units for comparison or take issue with the fact that the West Phoenix units were constructed in the early 1970's while Palo Verde was completed in 1986, there is no escaping a conclusion that generating facility costs are caused in large part by a desire to efficiently provide energy throughout the year. Otherwise, APS would not have incurred the higher nuclear generation capacity costs and its generating fleet could be made up solely of combustion turbines to meet peak demand. To serve loads for only four peak hours in a year, APS could rationalize West Phoenix CT operating expenses that are orders of magnitude higher than the expense per KW associated with nuclear base load generation, but the lower operating costs of the nuclear facilities justify the large capital investment because they operate throughout the year.

Q. Do other Arizona utilities with summer peaking characteristics employ an energy-weighted production demand allocation methodology comparable to what you are recommending for APS?

A. Yes. I understand that Tucson Electric Power ("TEP") has employed a 4CP & Average approach. In its Decision No. 58497 in TEP Docket No. U-1933-93-006, the Commission stated:

> An electric utility's total cost of service results from three major interrelated causes: total output; the rate and time when customers use the output; and, the number of customers who receive service. In order to reflect these three major interrelated cost factors in rates, an electric utility's total costs are functionalized and then classified as energy-related, demand-related and customer-related. Once an electric utility's total costs

> have been classified, they are then allocated among the various classes of customers by the most appropriate allocation ratio.
>
> In recent cases, the Commission has indicated its dissatisfaction with the four-month coincident peak (4CP) method for allocating production and transmission costs. At the same time, the Commission recognized that other methodologies took into consideration annual energy usage and peak demand.
>
> TEP conducted a COS study using the average and four coincident peak ("A&4CP") production approach. DOD also conducted a COS study utilizing a demand based average of four coincident peak ("4CP") methodology. JSA recommended adoption of an average and excess four coincident peak allocation study ("A&E/4CP"). RUCO modified the Company's COS study to arrive at its recommended class revenue allocation. Staff generally accepted the Company's COS study with comments/criticisms. (Decision No. 58497, page 75)

After stating the positions of other parties in greater detail in this Decision, the Commission ultimately stated at page 77 of the Decision, "Based on all the above, we concur that TEP's COS study is a useful guide in establishing appropriate rates in this case."

In addition, I understand that Commission Staff has employed energy-weighted allocation methods to production costs in cases involving electric cooperatives in Arizona.[2]

Q. Earlier in your testimony, you mentioned that Staff and RUCO opposed the APS production demand allocation factor in the Company's last rate case, Docket No. E-01345A-03-0437. Were the reasons given by the Staff and RUCO witnesses in that docket consistent with your views in this docket?

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[2] See for example, Decision No. 61721 in Duncan Valley Electric Cooperative Docket No. E-017003A-98-0431, Stipulation page 3 at "6. Cost-of-Service-Study, Load Research and Line Losses"

A. I believe so, yes. In the last APS rate case, Staff witness Ms. Lee Smith recommended an energy-weighted allocation approach, stating the following:

> For the most part I support the company's choice of allocators. However, I believe that the allocation of generation capacity costs is incorrect...The 4CP allocation method for generation capacity does not reflect cost causation because it does not reflect how the utility makes decisions regarding generation investment. Using the 4CP method implies that all generation capacity costs can be explained by the utility's need to meet its peak load. While it is true that the amount of capacity in MW's that a utility will build (or purchase) is determined by its need to meet its peak load, the types of generation capacity that the utility acquires, and thus the dollars that it spends on capacity, are affected by a number of other considerations, bur primarily by the tradeoff between capacity and energy costs.

RUCO witness Dr. Stutz also recommended using an energy weighting approach in the allocation of production capacity costs in the last APS rate case, as explained at page 20 of his testimony in Docket No. E-01345A-03-0437:

> Utility planners can choose different types of generating plants to meet customer loads. Peaking plants offer the advantage of lower costs but they are generally more expensive to run. Baseload plants, on the other hand, are more costly to build but have lower running costs. The choice of plant additions requires detailed analysis. However, underlying that analysis is the simple point that utility planners will only build more expensive baseload plants if they produce sufficient operating cost savings to outweigh their higher capital costs. Thus, the additional cost of baseload plants is justified by potential energy cost savings. The same is true for transmission lines. Both their role in meeting peak demand and their capacity to reduce costs by providing access to economic energy sources is considered.
>
> If APS only considered peak demands, then peaking plants would predominate in its generating mix because they are the cheapest plant sot build to meet a given demand. However, as Mr. Wheeler, APS's lead witness points out, the APS generation mix contains 44 percent coal as well as 31 percent nuclear units. The cost of coal and nuclear plants cannot be justified solely to meet peak demand.

These recommendations are consistent with the approach that I am recommending in this docket.

Q. How did APS respond to the recommendation of Staff and RUCO in the last case that production demand-related costs be allocated using an energy-weighted allocation approach?

A. In Rebuttal Testimony, APS witness Mr. Alan Propper listed several reasons "...for continuing to use a Coincident Peak methodology as opposed to the methodologies proposed by Staff and RUCO." Mr. Propper's listed reasons included his opinion that the 4CP method "best reflects generation capacity cost responsibility for a consistently strong summer peaking utility such as APS" and that "The Coincident Peak methodology uses a true demand (kW) allocation for what is a fixed cost, namely generation capacity, as opposed to an energy (kWh) allocation which is suitable for use with a variable cost such as fuel expense."

Q. Are these arguments a reasonable basis to <u>not</u> employ an energy-weighted allocation methodology as recommended by Staff then and now?

A. No. As explained in my earlier testimony, generation capacity cost causation for APS involves costs incurred by APS to install less expensive peaking units to meet peak demands, as well as substantial additional costs incurred to install more costly baseload generating units that produce energy at lower costs. It is important to note that an energy allocation factor is used by APS and Staff to

allocate actual fuel and other variable energy-related costs among customer classes. Because APS energy costs are lower as a result of the Company's diversified mix of generation resources, including baseload nuclear and coal units, equity requires that the classes receiving allocated energy savings also bear some increased cost responsibility for the large investment in such generating facilities. It is important to use an energy-weighted production demand allocation factor to match the benefits and costs associated with the APS mix of generation resources. The fact that APS is a strong summer-peaking utility does not change the fact that generating resources have been planned to minimize electricity production costs in the summer and throughout the year.

Q. Mr. Propper also testified in the last rate case that, "The Commission has consistently accepted the 4CP methodology in APS proceedings." Did you find this to be correct?

A. I have not found any recent Commission decisions in which there was a determination that the 4CP method advocated by APS was reasonable over other methods. Many APS rate changes have been implemented based upon settlements before the Commission, but in Docket No. U-1345-85-367 in 1988 the Commission resolved cost of service and rate design issues in a litigated APS rate case, with an extensive discussion of cost of service including the following language:

> Much of the testimony offered by the expert witnesses attempted to demonstrate why their particular cost allocation

> methodology was superior to all others. However, we are not prepared to endorse for general application any single method of cost allocation. Further, although we have previously indicated our dissatisfaction with the 4-CP method for allocating demand related production costs of nuclear generating units [footnote 38], we do not believe that the evidence warrants the selection of any single alternative method for rate design purposes in this case.
>
> Based on our review of the return indexes, our dissatisfaction with the 4-CP method for allocating demand-related nuclear production costs and the evidence that the dramatic test year reversal of the trend towards unity could have been an aberration, we agree with Mr. Violette's recommendations regarding the allocation of the required increase in gross annual revenues. Thus, the increase should be spread across the board to the Residential, General Service, Irrigation, and Street Lighting classes by the application of an equal percentage increase to the base revenues for each class, excluding basic service charge and fuel revenues. (Decision No. 55931, pages 83-84)

Footnote 38 in that Decision acknowledged the inability of the 4-CP method of allocation to reasonably treat the "trade-off" between demand-related capacity costs and the energy cost savings created by baseload units:

> 38. Our dissatisfaction with the 4-CP method for nuclear plant does not stem from the absolute size of the nuclear production costs, per se. Rather, it is the relationship between those relatively high costs (allocated by a demand ratio) which were incurred to take advantage of the relatively low nuclear fuel costs (allocated by the energy ratio), which has caused our dissatisfaction. Although there is always a "trade-off" between demand and energy costs, in the case of nuclear plants the relationship is exaggerated, particularly in the early years of the plant.

At the end of its discussion of cost of service allocations in Decision No. 55931, at page 85, the Commission concluded, "APS should continue to provide the cost-of-service data it provided in this case. In addition, in the next general rate case we would also like to consider more carefully the feasibility of an allocation methodology which reflects both energy and peak demand. Of

course, APS and the other parties can continue to offer other alternatives in addition to those presented in this case."

Q. Another concern raised by Mr. Propper in his rebuttal to Staff in the last rate case was that Staff's proposed method would "...shift approximately $5.1 million in annual costs or revenue requirement away from APS' Commission jurisdictional customers and inappropriately places it on the non-jurisdictional FERC customers. Since FERC does not accept the Average & Peak methodology, APS would not be able to recover this $5.1 million in cost from either jurisdiction, effectively 'stranding' dollars between state and federal regulation." Does this occur in using the 4CP & Average method you propose?

A. No. I have elected to <u>not</u> disturb the jurisdictional allocation of production plant in this docket, so that no jurisdictional "stranding" of costs will occur. The 4CP & Average calculation I performed was limited to revision of only the retail class allocation factors, such that the percentage of production demand-related costs allocated to the non-jurisdictional FERC customers is unchanged and is still based upon 4CP allocations. This modification impacts revenue requirement far less than in the last rate case and the concern raised by APS is easily avoided by my change in approach.

Q. Have you concurred in the APS treatment of transmission costs in its COSS study?

1 A. Yes. Transmission costs are treated as entirely non-jurisdictional, while the
2 retail jurisdiction is charged for transmission services needed for native load at
3 the FERC Open Access Transmission Tariff rates that are now effective. This
4 was the resolution of this issue in settlement of the last APS rate case.
5
6 Q. Does that conclude your direct testimony?
7 A. Yes, it does.

Michael L. Brosch
Utilitech, Inc. – President
Bachelor of Business Administration (Accounting)
University of Missouri-Kansas City (1978)
Certified Public Accountant Examination (1979)

GENERAL

Mr. Brosch serves as the director of regulatory projects for the firm and is responsible for the planning, supervision and conduct of firm engagements. His academic background is in business administration and accounting and he holds CPA certificates in Kansas and Missouri.

EXPERIENCE

Mr. Brosch has supervised and conducted the preparation of rate case exhibits and testimony in support of revenue requirements of electric, gas, telephone, water, and sewer utilities in response to tariff change proposals as a consultant and while employed by the Missouri Commission Staff. Responsible for virtually all facets of revenue requirement determination cost of service allocations and tariff implementation in addition to involvement in numerous special project investigations.

Industry restructuring analysis for gas utility rate unbundling, deregulation, competitive bidding and strategic planning, with testimony on regulatory processes, asset identification and classification, revenue requirement and unbundled rate designs and class cost of service studies.

Responsible for analysis and presentation of income tax related issues within ratemaking proceedings involving interpretation of relevant IRS code provisions and regulatory restrictions.

Conducted extensive review of the economic impact upon regulated utility companies of various transactions involving affiliated companies. Reviewed the parent-subsidiary relationships of integrated utility holding companies to determine appropriate treatment of consolidated tax benefits and capital costs. Sponsored testimony on affiliated interests in numerous Bell and major independent telephone company rate proceedings.

Has substantial experience in the application of lead-lag study concepts and methodologies in determination of working capital investment to be included in rate base.

Alternative regulation analyses and consultation to clients in Arizona, California and Oklahoma, focused upon challenges introduced by cost-based regulation, incentive effects available through alternative regulation and balancing of risks, opportunities and benefits among stakeholders.

Mr. Brosch managed the detailed regulatory review of utility mergers and acquisitions, diversification studies and holding company formation issues in energy and telecommunications transactions in multiple states. Sponsored testimony regarding merger synergies, merger accounting and tax implications, regulatory planning and price path strategies. Traditional horizontal utility mergers as well as leveraged buyouts of utility properties by private equity investors were addressed in several states.

Analyzed the regulation of telephone company publishing affiliates, including the propriety of continued imputation of directory publishing profits and the valuation of publishing affiliates, including the identification and quantification of intangible assets and benefits of affiliation with the regulated business in Arizona, Indiana, Washington and Utah.

WORK HISTORY

1985 - Present — **Principal** - Utilitech, Inc. (Previously Dittmer, Brosch and Associates, Inc.)

1983 - 1985: — **Project manager** - Lubow McKay Stevens and Lewis.
Responsible for supervision and conduct of utility regulatory projects on behalf of industry and regulatory agency clients.

1982 - 1983: — **Regulatory consultant** - Troupe Kehoe Whiteaker and Kent.
Responsible for management of rate case activities involving analysis of utility operations and results, preparation of expert testimony and exhibits, and issue development including research and legal briefs. Also involved in numerous special projects including financial analysis and utility systems planning. Taught firm's professional education course on "utility income taxation - ratemaking and accounting considerations" in 1982.

1978 - 1982: — **Senior Regulatory Accountant** - Missouri Public Service Commission.
Supervised and conducted rate case investigations of utilities subject to PSC jurisdiction in response to applications for tariff changes. Responsibilities included development of staff policy on ratemaking issues, planning and evaluating work of outside consultants, and the production of comprehensive testimony and exhibits in support of rate case positions taken.

OTHER QUALIFICATIONS

Bachelor of Business Administration - Accounting, 1978
University of Missouri - Kansas City "with distinction"

Member
American Institute of Certified Public Accountants
Missouri Society of Certified Public Accountants
Beta Alpha Psi, professional accounting scholastic fraternity
Kansas Society of Certified Public Accountants

Attended
Iowa State Regulatory Conference 1981, 1985
Regulated Industries Symposium 1979, 1980
Michigan State Regulatory Conference 1981
United States Telephone Association Round Table 1984
NARUC/NASUCA Annual Meeting 1988, Speaker
NARUC/NASUCA Annual Meeting 2000, Speaker

Instructor
INFOCAST Ratemaking Courses
Arizona Staff Training
Hawaii Staff Training

Michael L. Brosch
Summary of Previously Filed Testimony
1981 through 2006

Utility	Jurisdiction	Agency	Docket/Case Number	Represented	Year	Addressed
Kansas City Power and Light Co.	Missouri	PSC	ER-81-42	Staff	1981	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-81-208	Staff	1981	Rate Base, Operating Income, Affiliated Interest
Northern Indiana Public Service	Indiana	PSC	36689	Consumers Counsel	1982	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	URC	37023	Consumers Counsel	1983	Rate Base, Operating Income, Cost Allocations
Mountain Bell Telephone	Arizona	ACC	9981-E1051-81-406	Staff	1982	Affiliated Interest
Sun City Water	Arizona	ACC	U-1656-81-332	Staff	1982	Rate Base, Operating Income
Sun City Sewer	Arizona	ACC	U-1656-81-331	Staff	1982	Rate Base, Operating Income
El Paso Water	Kansas	City Counsel	Unknown	Company	1982	Rate Base, Operating Income, Rate of Return
Ohio Power Company	Ohio	PUCO	83-98-EL-AIR	Consumer Counsel	1983	Operating Income, Rate Design, Cost Allocations
Dayton Power & Light Company	Ohio	PUCO	83-777-GA-AIR	Consumer Counsel	1983	Rate Base
Walnut Hill Telephone	Arkansas	PSC	83-010-U	Company	1983	Operating Income, Rate Base
Cleveland Electric Illum.	Ohio	PUCO	84-188-EL-AIR	Consumer Counsel	1984	Rate Base, Operating Income, Cost Allocations
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC	Consumer Counsel	1984	Fuel Clause
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC (Subfile A)	Consumer Counsel	1984	Fuel Clause
General Telephone - Ohio	Ohio	PUCO	84-1026-TP-AIR	Consumer Counsel	1984	Rate Base
Cincinnati Bell Telephone	Ohio	PUCO	84-1272-TP-AIR	Consumer Counsel	1985	Rate Base
Ohio Bell Telephone	Ohio	PUCO	84-1535-TP-AIR	Consumer Counsel	1985	Rate Base
United Telephone - Missouri	Missouri	PSC	TR-85-179	Staff	1985	Rate Base, Operating Income
Wisconsin Gas	Wisconsin	PSC	05-UI-18	Staff	1985	Diversification-Restructuring
United Telephone - Indiana	Indiana	URC	37927	Consumer Counsel	1986	Rate Base, Affiliated Interest
Indianapolis Power & Light	Indiana	URC	37837	Consumer Counsel	1986	Rate Base
Northern Indiana Public Service	Indiana	URC	37972	Consumer Counsel	1986	Plant Cancellation Costs
Northern Indiana Public Service	Indiana	URC	38045	Consumer Counsel	1986	Rate Base, Operating Income, Cost Allocations, Capital Costs
Arizona Public Service	Arizona	ACC	U-1435-85-367	Staff	1987	Rate Base, Operating Income, Cost Allocations
Kansas City, KS Board of Public Utilities	Kansas	BPU	87-1	Municipal Utility	1987	Operating Income, Capital Costs
Detroit Edison	Michigan	PSC	U-8683	Industrial Customers	1987	Income Taxes

Michael L. Brosch
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1981 through 2006

Consumers Power	Michigan	PSC	U-8681	Industrial Customers	1987	Income Taxes
Consumers Power	Michigan	PSC	U-8680	Industrial Customers	1987	Income Taxes
Northern Indiana Public Service	Indiana	URC	38365	Consumer Counsel	1987	Rate Design
Indiana Gas	Indiana	URC	38080	Consumer Counsel	1987	Rate Base
Northern Indiana Public Service	Indiana	URC	38380	Consumers Counsel	1988	Rate Base, Operating Income, Rate Design, Capital Costs
Terre Haute Gas	Indiana	URC	38515	Consumers Counsel	1988	Rate Base, Operating Income, Capital Costs
United Telephone -Kansas	Kansas	KCC	162,044-U	Consumers Counsel	1989	Rate Base, Capital Costs, Affiliated Interest
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income, Affiliate Interest
All Kansas Electrics	Kansas	KCC	140,718-U	Consumers Counsel	1989	Generic Fuel Adjustment Hearing
Southwest Gas	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income, Affiliated Interest
American Telephone and Telegraph	Kansas	KCC	167,493-U	Consumers Counsel	1990	Price/Flexible Regulation, Competition, Revenue Requirements
Indiana Michigan Power	Indiana	URC	38728	Consumer Counsel	1989	Rate Base, Operating Income, Rate Design
People Gas, Light and Coke Company	Illinois	ICC	90-0007	Public Counsel	1990	Rate Base, Operating Income
United Telephone Company	Florida	PSC	891239-TL	Public Counsel	1990	Affiliated Interest
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1990	Rate Base, Operating Income (Testimony not admitted)
Arizona Public Service Company	Arizona	ACC	U-1345-90-007	Staff	1991	Rate Base, Operating Income
Indiana Bell Telephone Company	Indiana	URC	39017	Consumer Counsel	1991	Test Year, Discovery, Schedule
Southwestern Bell Telephone Company	Oklahoma	OCC	39321	Attorney General	1991	Remand Issues
UtiliCorp United/ Centel	Kansas	KCC	175,476-U	Consumer Counsel	1991	Merger/Acquisition
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
United Telephone - Florida	Florida	PSC	910980-TL	Public Counsel	1992	Affiliated Interest
Hawaii Electric Light Company	Hawaii	PUC	6999	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Maui Electric Company	Hawaii	PUC	7000	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Southern Bell Telephone Company	Florida	PSC	920260-TL	Public Counsel	1992	Affiliated Interest
US West Communications	Washington	WUTC	U-89-3245-P	Attorney General	1992	Alternative Regulation
UtiliCorp United/ MPS	Missouri	PSC	ER-93-37	Staff	1993	Affiliated Interest

Michael L. Brosch
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Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-1151, 1144, 1190	Attorney General	1993	Rate Base, Operating Income, Take or Pay, Rate Design
Public Service Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Affiliated Interest
Illinois Bell Telephone	Illinois	ICC	92-0448 92-0239	Citizens Board	1993	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Hawaii Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	URC	39584	Consumer Counselor	1994	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Cost Allocations, Rate Design
PSI Energy, Inc.	Indiana	URC	39584-S2	Consumer Counselor	1994	Merger Costs and Cost Savings, Non-Traditional Ratemaking
Transok, Inc.	Oklahoma	OCC	PUD-1342	Staff	1994	Rate Base, Operating Income, Affiliated Interest, Allocations
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income, Cost of Service, Rate Design
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Operating Income, Affiliate Interest, Service Quality
PSI Energy, Inc.	Indiana	URC	40003	Consumer Counselor	1995	Rate Base, Operating Income
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-880000598	Attorney General	1995	Stand-by Tariff
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	PUC 94-0298	Consumer Advocate	1996	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
Mid-American Energy Company	Iowa	ICC	APP-96-1	Consumer Advocate	1996	Non-Traditional Ratemaking
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income, Rate Design, Non-Traditional Ratemaking
Southwest Gas Corporation	Arizona	ACC	U-1551-96-596	Staff	1997	Operating Income, Affiliated Interest, Gas Supply
Utilicorp United - Missouri Public Service Division	Missouri	PSC	EO-97-144	Staff	1997	Operating Income
US West Communications	Utah	PSC	97-049-08	Consumer Advocate	1997	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
US West Communications	Washington	WUTC	UT-970766	Attorney General	1997	Rate Base, Operating Income
Missouri Gas Energy	Missouri	PSC	GR 98-140	Public Counsel	1998	Affiliated Interest
ONEOK	Oklahoma	OCC	PUD980000177	Attorney General	1998	Gas Restructuring, rate Design, Unbundling
Nevada Power/Sierra Pacific Power Merger	Nevada	PSC	98-7023	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting

Michael L. Brosch
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PacifiCorp / Utah Power	Utah	PSC	97-035-1	Consumer Advocate	1998	Affiliated Interest
MidAmerican Energy / CalEnergy Merger	Iowa	PUB	SPU-98-8	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
American Electric Power / Central and South West Merger	Oklahoma	OCC	980000444	Attorney General	1998	Merger Savings, Rate Plan and Accounting
ONEOK Gas Transportation	Oklahoma	OCC	970000088	Attorney General	1998	Cost of Service, Rate Design, Special Contract
U S West Communications	Washington	WUTC	UT-98048	Attorney General	1999	Directory Imputation and Business Valuation
U S West / Qwest Merger	Iowa	PUB	SPU 99-27	Consumer Advocate	1999	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Washington	WUTC	UT-991358	Attorney General	2000	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Utah	PSC	99-049-41	Consumer Advocate	2000	Merger Impacts, Service Quality and Accounting
PacifiCorp / Utah Power	Utah	PSC	99-035-10	Consumer Advocate	2000	Affiliated Interest
Oklahoma Natural Gas, ONEOK Gas Transportation	Oklahoma	OCC	980000683, 980000570, 990000166	Attorney General	2000	Operating Income, Rate Base, Cost of Service, Rate Design, Special Contract
U S West Communications	New Mexico	PRC	3008	Staff	2000	Operating Income, Directory Imputation
U S West Communications	Arizona	ACC	T-0105B-99-0105	Staff	2000	Operating Income, Rate Base, Directory Imputation
Northern Indiana Public Service Company	Indiana	IURC	41746	Consumer Counsel	2001	Operating Income, Rate Base, Affiliate Transactions
Nevada Power Company	Nevada	PUCN	01-10001	Attorney General-BCP	2001	Operating Income, Rate Base, Merger Costs, Affiliates
Sierra Pacific Power Company	Nevada	PUCN	01-11030	Attorney General-BCP	2002	Operating Income, Rate Base, Merger Costs, Affiliates
The Gas Company, Division of Citizens Communications	Hawaii	PUC	00-0309	Consumer Advocate	2001	Operating Income, Rate Base, Cost of Service, Rate Design
SBC Pacific Bell	California	PUC	I.01-09-002 R.01-09-001	Office of Ratepayer Advocate	2002	Depreciation, Income Taxes and Affiliates
Midwest Energy, Inc.	Kansas	KCC	02-MDWG-922-RTS	Agriculture Customers	2002	Rate Design, Cost of Capital
Qwest Communications – Dex Sale	Utah	PSC	02-049-76	Consumer Advocate	2003	Directory Publishing
Qwest Communications – Dex Sale	Washington	WUTC	UT-021120	Attorney General	2003	Directory Publishing
Qwest Communications – Dex Sale	Arizona	ACC	T-0105B-02-0666	Staff	2003	Directory Publishing
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counsel	2003	Operating Income, Rate Trackers, Cost of Service, Rate Design
Qwest Communications – Price Cap Review	Arizona	ACC	T-0105B-03-0454	Staff	2004	Operating Income, Rate Base, Fair Value, Alternative Regulation

Michael L. Brosch
Summary of Previously Filed Testimony
1981 through 2006

Verizon Northwest Corp	Washington	WUTC	UT-040788	Public Counsel	2004	Directory Publishing, Rate Base, Operating Income
Citizens Gas & Coke Utility	Indiana	IURC	42767	Consumer Counsel	2005	Operating Income, Debt Service, Working Capital, Affiliate Transactions, Alternative Regulation
Hawaiian Electric Company	Hawaii	HPUC	04-0113	Consumer Advocate	2005	Operating Income, Rate Base, Cost of Service, Rate Design
Sprint/Nextel Corporation	Washington	WUTC	UT-051291	Public Counsel	2006	Directory Publishing, Corporate Reorganization
Puget Sound Energy, Inc.	Washington	WUTC	UE-060266 and UG-060267	Public Counsel	2006	Alternative Regulation
Cascade Natural Gas Corporation	Washington	WUTC	UG-060256	Public Counsel	2006	Alternative Regulation
Hawaiian Electric Company	Hawaii	HPUC	05-0146	Consumer Advocate	2006	Community Benefits Program

STAFF REVENUE REQUIREMENT - 4CP AVERAGE ALLOCATION
STAFF POSITION

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

Line No.	Description	GJ ELECTRIC TOTAL (1)	GJ ACC JURISDICTION (2)	GJ ALL OTHER (3)
	SUMMARY OF RESULTS			
1	DEVELOPMENT OF RATE BASE			
2	ELECTRIC PLANT IN SERVICE	$10,096,271,000	$8,556,179,618	$1,540,091,382
3	GENERAL & INTANGIBLE PLANT	$722,630,705	$666,173,004	$56,457,701
4	LESS: RESERVE FOR DEPRECIATION	($4,170,525,134)	($3,548,546,146)	($621,978,988)
5	OTHER DEFERRED CREDITS	($448,168,000)	($438,604,344)	($9,563,656)
6	WORKING CASH	($29,138,598)	($25,220,726)	($3,917,872)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$197,285,248	$177,653,628	$19,631,620
8	ACCUM. DEFERRED TAXES	($1,203,998,000)	($1,062,992,832)	($141,005,168)
9	REGULATORY ASSETS	($80,002,029)	($93,364,564)	$13,362,535
10	DECOMMISSIONING FUND	$290,537,000	$285,856,167	$4,680,833
11	GAIN FROM DISP. OF PLANT	($46,901,000)	($46,360,307)	($540,693)
12	MISCELLANEOUS DEFERRED DEBITS	$42,522,000	$39,464,108	$3,057,892
13	CUSTOMER ADVANCES	($59,807,000)	($59,807,000)	$0
14	CUSTOMER DEPOSITS	($54,860,000)	($54,860,000)	$0
15	PROFORMA ADJUSTMENTS	($1,314,161)	$5,559,077	($6,873,238)
16	TOTAL RATE BASE	$5,254,532,031	$4,401,129,682	$853,402,349
17				
18	DEVELOPMENT OF RETURN			
19	REVENUES FROM RATES	$2,103,857,729	$2,066,144,726	$37,713,003
20	PROFORMA TO REVENUES FROM RATES	$65,860,308	$66,084,186	($223,878)
21	OTHER ELECTRIC REVENUE	$476,428,509	$458,779,789	$17,648,720
22	TOTAL OPERATING REVENUES	$2,646,146,546	$2,591,008,701	$55,137,845
23				
24	OPERATING EXPENSES			
25	OPERATION & MAINTENANCE	$2,246,012,697	$2,302,448,767	($56,436,070)
26	ADMINISTRATIVE & GENERAL	$141,768,183	$132,687,128	$9,081,055
27	DEPRECIATION & AMORT EXPENSE	$321,526,000	$285,758,990	$35,767,010
28	AMORTIZATION ON GAIN	($6,613,638)	($6,528,055)	($85,583)
29	REGULATORY ASSETS	($2,203,510)	($2,203,510)	$0
30	PROFORMA ADJUSTMENTS	($540,817,385)	($531,955,639)	($8,861,746)
31	TAXES OTHER THAN INCOME	$139,970,767	$116,332,654	$23,638,113
32	INCOME TAX	$75,695,673	$64,509,260	$11,186,413
33	TOTAL OPERATING EXPENSES	$2,375,338,788	$2,361,049,596	$14,289,191
34				
35	OPERATING INCOME	$270,807,758	$229,959,105	$40,848,654
36				
37	RETURN	$270,807,758	$229,959,105	$40,848,654
38				
39	RATE OF RETURN (PRESENT)	5.15%	5.23%	4.79%
40				
41	INDEX RATE OF RETURN (PRESENT)	1.00	1.01	0.93

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
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Line No.	Description	TOTAL RETAIL (4)	RESIDENTIAL (5)	GENERAL SERVICE (6)	E-38,221 (Water Pumping) (7)	STREET LIGHTING (8)	DUSK TO DAWN (9)
		<---------- GE-1 ---------->					
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$8,556,179,618	$4,602,622,773	$3,764,548,986	$61,903,231	$88,281,830	$38,822,797
3	GENERAL & INTANGIBLE PLANT	$666,173,004	$409,819,210	$243,171,737	$4,251,264	$6,282,265	$2,648,529
4	LESS: RESERVE FOR DEPRECIATION	($3,548,546,146)	($1,896,798,579)	($1,579,361,207)	($27,268,845)	($31,701,586)	($13,415,930)
5	OTHER DEFERRED CREDITS	($438,604,344)	($225,458,670)	($207,896,857)	($3,462,122)	($1,361,185)	($425,510)
6	WORKING CASH	($25,220,726)	($12,591,199)	($12,141,693)	($154,998)	($232,543)	($100,295)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$177,653,628	$91,140,849	$83,008,225	$1,511,753	$1,434,729	$558,072
8	ACCUM. DEFERRED TAXES	($1,062,992,832)	($565,575,102)	($478,247,836)	($6,013,443)	($9,163,195)	($3,993,256)
9	REGULATORY ASSETS	($93,364,564)	($47,382,588)	($45,472,456)	($487,357)	($27,374)	$5,209
10	DECOMMISSIONING FUND	$285,856,167	$135,532,339	$145,260,236	$3,481,853	$1,280,428	$301,312
11	GAIN FROM DISP. OF PLANT	($46,360,307)	($23,341,404)	($22,595,028)	($334,372)	($72,454)	($17,050)
12	MISCELLANEOUS DEFERRED DEBITS	$39,464,108	$24,261,926	$14,422,780	$251,962	$371,050	$156,389
13	CUSTOMER ADVANCES	($59,807,000)	($43,338,952)	($13,858,832)	($2,407,716)	($201,500)	$0
14	CUSTOMER DEPOSITS	($54,860,000)	($29,075,800)	($24,737,362)	($564,674)	($330,038)	($152,126)
15	PROFORMA ADJUSTMENTS	$5,559,077	$897,529	$5,246,267	$86,961	($457,853)	($213,828)
16	TOTAL RATE BASE	$4,401,129,682	$2,420,712,334	$1,871,346,960	$30,793,498	$54,102,574	$24,174,315
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$2,066,144,726	$1,058,729,739	$967,398,538	$20,966,540	$12,913,053	$6,136,856
20	PROFORMA TO REVENUES FROM RATES	$66,084,186	$33,316,369	$32,153,204	($102,439)	$431,212	$285,840
21	OTHER ELECTRIC REVENUE	$458,779,789	$219,693,023	$228,817,968	$5,343,456	$4,254,055	$671,287
22	TOTAL OPERATING REVENUES	$2,591,008,701	$1,311,739,131	$1,228,369,710	$26,207,557	$17,598,320	$7,093,983
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$2,302,448,767	$1,138,939,802	$1,120,781,069	$25,864,564	$13,522,261	$3,341,071
26	ADMINISTRATIVE & GENERAL	$132,687,128	$80,699,072	$49,016,359	$1,006,399	$1,376,867	$588,431
27	DEPRECIATION & AMORT EXPENSE	$285,758,990	$157,680,051	$121,235,690	$2,187,881	$3,237,745	$1,417,623
28	AMORTIZATION ON GAIN	($6,528,055)	($3,227,883)	($3,223,300)	($57,045)	($16,050)	($3,777)
29	REGULATORY ASSETS	($2,203,510)	($1,144,245)	($1,049,237)	($10,028)	$0	$0
30	PROFORMA ADJUSTMENTS	($531,955,639)	($251,433,939)	($269,355,402)	($7,199,427)	($3,117,805)	($849,067)
31	TAXES OTHER THAN INCOME	$116,332,654	$64,881,575	$48,396,437	$871,630	$1,510,049	$672,963
32	INCOME TAX	$64,509,260	$22,373,128	$40,763,004	$986,541	($93,858)	$480,445
33	TOTAL OPERATING EXPENSES	$2,361,049,596	$1,208,767,563	$1,106,564,620	$23,650,515	$16,419,209	$5,647,690
34							
35	OPERATING INCOME	$229,959,105	$102,971,568	$121,805,090	$2,557,042	$1,179,112	$1,446,293
36							
37	RETURN	$229,959,105	$102,971,568	$121,805,090	$2,557,042	$1,179,112	$1,446,293
38							
39	RATE OF RETURN (PRESENT)	5.23%	4.25%	6.51%	8.30%	2.18%	5.98%
40							
41	INDEX RATE OF RETURN (PRESENT)	1.01	0.83	1.26	1.61	0.42	1.16

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
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Line No.	Description	TOTAL GENERAL SVC (10)	E-20 (Church Rate) (11)	E-30, E-32 (0 - 20 kW) (12)	E-32 (21 - 100 kW) (13)	E-32 (101 - 400 kW) (14)	E-32 (401 - 999 kW) (15)	E-32 (1,000 + kW) (16)	E-34 (17)	E-35 (18)
		<---------- GE-2 ---------->								
	SUMMARY OF RESULTS									
1	DEVELOPMENT OF RATE BASE									
2	ELECTRIC PLANT IN SERVICE	$3,764,548,986	$13,679,245	$656,098,930	$892,167,281	$848,257,037	$498,862,670	$377,642,500	$253,463,175	$224,378,148
3	GENERAL & INTANGIBLE PLANT	$243,171,737	$826,389	$49,786,704	$55,926,714	$50,386,041	$30,576,836	$23,394,716	$16,086,933	$16,187,402
4	LESS: RESERVE FOR DEPRECIATION	($1,579,361,207)	($5,208,752)	($256,260,916)	($363,391,966)	($360,466,930)	($216,764,101)	($161,684,879)	($110,545,733)	($105,037,929)
5	OTHER DEFERRED CREDITS	($207,896,857)	($539,468)	($30,115,445)	($44,818,356)	($47,013,066)	($29,215,741)	($23,177,050)	($16,118,629)	($16,899,102)
6	WORKING CASH	($12,141,693)	($43,109)	($1,880,898)	($2,802,224)	($2,789,068)	($1,677,517)	($1,285,564)	($869,182)	($794,132)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$83,008,225	$272,101	$11,590,935	$17,785,164	$18,942,716	$12,179,392	$9,141,823	$6,408,033	$6,688,060
8	ACCUM. DEFERRED TAXES	($478,247,836)	($1,643,489)	($82,006,194)	($112,067,146)	($107,168,956)	($63,173,349)	($49,180,307)	($33,053,301)	($29,955,094)
9	REGULATORY ASSETS	($45,472,456)	($98,865)	($7,021,994)	($10,153,502)	($10,199,677)	($6,012,251)	($5,065,899)	($3,445,706)	($3,474,561)
10	DECOMMISSIONING FUND	$145,260,236	$396,517	$14,406,781	$27,667,366	$34,001,927	$23,592,112	$17,516,133	$12,742,045	$14,937,355
11	GAIN FROM DISP. OF PLANT	($22,595,028)	($55,271)	($3,321,005)	($4,958,184)	($5,129,225)	($3,106,666)	($2,520,407)	($1,734,649)	($1,769,621)
12	MISCELLANEOUS DEFERRED DEBITS	$14,422,780	$48,948	$2,948,928	$3,316,348	$2,989,814	$1,814,354	$1,388,622	$954,864	$960,901
13	CUSTOMER ADVANCES	($13,858,832)	($47,917)	($2,038,227)	($3,125,023)	($3,289,801)	($2,093,348)	($1,348,834)	($955,473)	($960,209)
14	CUSTOMER DEPOSITS	($24,737,362)	($85,530)	($3,638,139)	($5,578,020)	($5,872,139)	($3,736,527)	($2,407,606)	($1,705,475)	($1,713,927)
15	PROFORMA ADJUSTMENTS	$5,246,267	($15,721)	$270,191	$891,732	$1,268,177	$760,272	$791,595	$564,839	$715,183
16	TOTAL RATE BASE	$1,871,346,960	$7,485,079	$348,819,652	$450,860,184	$413,916,850	$242,006,137	$183,204,842	$121,791,741	$103,262,475
17										
18	DEVELOPMENT OF RETURN									
19	REVENUES FROM RATES	$967,398,538	$3,344,799	$142,275,889	$218,138,380	$229,640,445	$146,123,538	$94,153,699	$66,695,622	$67,026,166
20	PROFORMA TO REVENUES FROM RATES	$32,153,204	$250,921	$9,919,877	$3,997,949	$15,079,785	$1,059,540	$1,018,113	$135,964	$691,055
21	OTHER ELECTRIC REVENUE	$228,817,968	$651,979	$23,956,956	$44,297,681	$53,381,703	$36,759,026	$27,225,054	$19,742,836	$22,802,733
22	TOTAL OPERATING REVENUES	$1,228,369,710	$4,247,699	$176,152,722	$266,434,010	$298,101,933	$183,942,104	$122,396,866	$86,574,422	$90,519,954
23										
24	OPERATING EXPENSES									
25	OPERATION & MAINTENANCE	$1,120,781,069	$3,128,440	$126,621,013	$219,609,967	$259,237,105	$176,429,598	$131,575,208	$95,038,418	$109,141,321
26	ADMINISTRATIVE & GENERAL	$49,016,359	$173,476	$9,916,047	$11,419,329	$10,337,611	$6,219,546	$4,655,748	$3,187,324	$3,107,279
27	DEPRECIATION & AMORT EXPENSE	$121,235,690	$455,396	$21,606,492	$28,660,970	$27,100,974	$16,097,638	$11,986,345	$8,080,975	$7,246,900
28	AMORTIZATION ON GAIN	($3,223,300)	($8,174)	($425,055)	($677,794)	($738,914)	($468,573)	($368,758)	($258,611)	($277,422)
29	REGULATORY ASSETS	($1,049,237)	($2,397)	($182,950)	($247,693)	($234,016)	($129,353)	($111,332)	($74,006)	($67,490)
30	PROFORMA ADJUSTMENTS	($269,355,402)	($736,963)	($23,522,830)	($52,154,313)	($58,247,680)	($46,249,800)	($33,786,836)	($25,418,410)	($29,238,569)
31	TAXES OTHER THAN INCOME	$48,396,437	$195,818	$9,056,807	$11,750,044	$10,805,909	$6,301,644	$4,626,033	$3,079,916	$2,580,266
32	INCOME TAX	$40,763,004	$306,854	$8,660,419	$13,072,703	$14,028,192	$6,964,924	($402,222)	($126,964)	($1,740,902)
33	TOTAL OPERATING EXPENSES	$1,106,564,620	$3,512,450	$151,729,942	$231,433,213	$262,289,181	$165,165,625	$118,174,186	$83,508,641	$90,751,383
34										
35	OPERATING INCOME	$121,805,090	$735,249	$24,422,780	$35,000,797	$35,812,752	$18,776,479	$4,222,680	$3,065,781	($231,429)
36										
37	RETURN	$121,805,090	$735,249	$24,422,780	$35,000,797	$35,812,752	$18,776,479	$4,222,680	$3,065,781	($231,429)
38										
39	RATE OF RETURN (PRESENT)	6.51%	9.82%	7.00%	7.76%	8.65%	7.76%	2.30%	2.52%	-0.22%
40										
41	INDEX RATE OF RETURN (PRESENT)	1.26	1.91	1.36	1.51	1.68	1.51	0.45	0.49	-0.04

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
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Line No.	Description	GE-3 TOTAL RESIDENTIAL (19)	RESIDENTIAL E-10 (20)	RESIDENTIAL E-12 (21)	RESIDENTIAL EC-1 (22)	RESIDENTIAL ET-1 (23)	RESIDENTIAL ECT-1 (24)
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$4,602,622,773	$283,119,906	$1,442,861,713	$156,429,020	$2,263,015,111	$457,197,023
3	GENERAL & INTANGIBLE PLANT	$409,819,210	$27,677,481	$147,822,129	$12,410,858	$187,476,540	$34,432,202
4	LESS: RESERVE FOR DEPRECIATION	($1,896,798,579)	($122,552,784)	($597,568,632)	($66,788,322)	($922,274,761)	($187,614,079)
5	OTHER DEFERRED CREDITS	($225,458,670)	($13,917,486)	($70,077,504)	($7,890,391)	($110,007,051)	($23,566,238)
6	WORKING CASH	($12,591,199)	($727,331)	($3,656,635)	($449,496)	($6,382,377)	($1,375,358)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$91,140,849	$5,699,478	$28,406,169	$3,216,206	$44,336,909	$9,482,088
8	ACCUM. DEFERRED TAXES	($565,575,102)	($34,021,969)	($175,851,099)	($19,128,016)	($279,219,903)	($57,354,116)
9	REGULATORY ASSETS	($47,382,588)	($2,766,310)	($14,244,476)	($1,645,942)	($23,613,421)	($5,112,439)
10	DECOMMISSIONING FUND	$135,532,339	$8,749,151	$41,051,666	$5,176,484	$65,386,973	$15,168,064
11	GAIN FROM DISP. OF PLANT	($23,341,404)	($1,394,609)	($7,018,565)	($826,997)	($11,584,864)	($2,516,369)
12	MISCELLANEOUS DEFERRED DEBITS	$24,261,926	$1,637,996	$8,747,030	$735,108	$11,101,662	$2,040,131
13	CUSTOMER ADVANCES	($43,338,952)	($2,879,259)	($14,760,504)	($1,501,737)	($20,077,388)	($4,120,063)
14	CUSTOMER DEPOSITS	($29,075,800)	($1,931,675)	($9,902,719)	($1,007,505)	($13,469,779)	($2,764,122)
15	PROFORMA ADJUSTMENTS	$897,529	($3,711)	($233,274)	$83,972	$706,428	$344,115
16	TOTAL RATE BASE	$2,420,712,334	$146,688,878	$775,575,299	$78,813,242	$1,185,394,078	$234,240,838
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$1,058,729,739	$70,337,587	$360,585,198	$36,686,029	$490,471,664	$100,649,261
20	PROFORMA TO REVENUES FROM RATES	$33,316,369	($2,061,923)	$12,766,411	($1,178,134)	$21,464,438	$2,325,577
21	OTHER ELECTRIC REVENUE	$219,693,023	$14,128,249	$66,958,622	$8,281,943	$106,067,571	$24,256,638
22	TOTAL OPERATING REVENUES	$1,311,739,131	$82,403,913	$440,310,231	$43,789,838	$618,003,673	$127,231,476
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$1,138,939,802	$74,029,391	$356,088,331	$41,939,808	$545,124,324	$121,757,949
26	ADMINISTRATIVE & GENERAL	$80,699,072	$5,448,647	$28,728,968	$2,490,346	$37,185,619	$6,845,492
27	DEPRECIATION & AMORT EXPENSE	$157,680,051	$9,947,593	$50,905,484	$5,267,895	$76,428,253	$15,130,825
28	AMORTIZATION ON GAIN	($3,227,883)	($197,429)	($972,689)	($116,992)	($1,588,879)	($351,894)
29	REGULATORY ASSETS	($1,144,245)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)
30	PROFORMA ADJUSTMENTS	($251,433,939)	($17,957,337)	($75,734,616)	($10,492,034)	($118,944,305)	($28,305,647)
31	TAXES OTHER THAN INCOME	$64,881,575	$4,085,518	$20,964,750	$2,153,015	$31,525,406	$6,152,887
32	INCOME TAX	$22,373,128	$1,182,253	$14,613,737	$183,916	$6,415,929	($22,708)
33	TOTAL OPERATING EXPENSES	$1,208,767,563	$76,472,960	$394,251,132	$41,386,961	$575,570,662	$121,085,848
34							
35	OPERATING INCOME	$102,971,568	$5,930,953	$46,059,099	$2,402,877	$42,433,011	$6,145,628
36							
37	RETURN	$102,971,568	$5,930,953	$46,059,099	$2,402,877	$42,433,011	$6,145,628
38							
39	RATE OF RETURN (PRESENT)	4.25%	4.04%	5.94%	3.05%	3.58%	2.62%
40							
41	INDEX RATE OF RETURN (PRESENT)	0.83	0.78	1.15	0.59	0.69	0.51

STAFF REVENUE REQUIREMENT - 4CP ALLOCATION
FOR COMPARISON ONLY

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

Line No.	Description	GJ ELECTRIC TOTAL (1)	GJ ACC JURISDICTION (2)	GJ ALL OTHER (3)
	SUMMARY OF RESULTS			
1	DEVELOPMENT OF RATE BASE			
2	ELECTRIC PLANT IN SERVICE	$10,096,271,000	$8,556,179,618	$1,540,091,382
3	GENERAL & INTANGIBLE PLANT	$722,630,705	$666,173,004	$56,457,701
4	LESS: RESERVE FOR DEPRECIATION	($4,170,525,134)	($3,548,546,146)	($621,978,988)
5	OTHER DEFERRED CREDITS	($448,168,000)	($438,604,344)	($9,563,656)
6	WORKING CASH	($29,138,598)	($25,220,726)	($3,917,872)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$197,285,248	$177,653,628	$19,631,620
8	ACCUM. DEFERRED TAXES	($1,203,998,000)	($1,062,992,832)	($141,005,168)
9	REGULATORY ASSETS	($80,002,029)	($93,364,564)	$13,362,535
10	DECOMMISSIONING FUND	$290,537,000	$285,856,167	$4,680,833
11	GAIN FROM DISP. OF PLANT	($46,901,000)	($46,360,307)	($540,693)
12	MISCELLANEOUS DEFERRED DEBITS	$42,522,000	$39,464,108	$3,057,892
13	CUSTOMER ADVANCES	($59,807,000)	($59,807,000)	$0
14	CUSTOMER DEPOSITS	($54,860,000)	($54,860,000)	$0
15	PROFORMA ADJUSTMENTS	($1,314,161)	$5,559,077	($6,873,238)
16	TOTAL RATE BASE	$5,254,532,031	$4,401,129,682	$853,402,349
17				
18	DEVELOPMENT OF RETURN			
19	REVENUES FROM RATES	$2,103,857,729	$2,066,144,726	$37,713,003
20	PROFORMA TO REVENUES FROM RATES	$65,860,308	$66,084,186	($223,878)
21	OTHER ELECTRIC REVENUE	$476,428,509	$458,779,789	$17,648,720
22	TOTAL OPERATING REVENUES	$2,646,146,546	$2,591,008,701	$55,137,845
23				
24	OPERATING EXPENSES			
25	OPERATION & MAINTENANCE	$2,246,012,697	$2,302,448,767	($56,436,070)
26	ADMINISTRATIVE & GENERAL	$141,768,183	$132,687,128	$9,081,055
27	DEPRECIATION & AMORT EXPENSE	$321,526,000	$285,758,990	$35,767,010
28	AMORTIZATION ON GAIN	($6,613,638)	($6,528,055)	($85,583)
29	REGULATORY ASSETS	($2,203,510)	($2,203,510)	$0
30	PROFORMA ADJUSTMENTS	($540,817,385)	($531,955,639)	($8,861,746)
31	TAXES OTHER THAN INCOME	$139,970,767	$116,332,654	$23,638,113
32	INCOME TAX	$75,695,673	$64,509,260	$11,186,413
33	TOTAL OPERATING EXPENSES	$2,375,338,788	$2,361,049,596	$14,289,191
34				
35	OPERATING INCOME	$270,807,758	$229,959,105	$40,848,654
36				
37	RETURN	$270,807,758	$229,959,105	$40,848,654
38				
39	RATE OF RETURN (PRESENT)	5.15%	5.23%	4.79%
40				
41	INDEX RATE OF RETURN (PRESENT)	1.00	1.01	0.93

STAFF REVENUE REQUIREMENT - 4CP ALLOCATION
FOR COMPARISON ONLY

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

Line No.	Description	TOTAL RETAIL (4)	RESIDENTIAL (5)	GENERAL SERVICE (6)	E-38,221 (Water Pumping) (7)	STREET LIGHTING (8)	DUSK TO DAWN (9)
		<---------- GE-1 ---------->					
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$8,556,179,618	$4,681,780,206	$3,708,391,092	$48,573,070	$80,454,414	$36,980,837
3	GENERAL & INTANGIBLE PLANT	$666,173,004	$413,695,677	$240,421,594	$3,598,464	$5,898,943	$2,558,325
4	LESS: RESERVE FOR DEPRECIATION	($3,548,546,146)	($1,928,646,856)	($1,556,766,586)	($21,905,575)	($28,552,296)	($12,674,834)
5	OTHER DEFERRED CREDITS	($438,604,344)	($230,684,114)	($204,189,689)	($2,582,154)	($844,471)	($303,917)
6	WORKING CASH	($25,220,726)	($12,831,079)	($11,971,511)	($114,602)	($208,823)	($94,713)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$177,653,628	$91,914,881	$82,459,091	$1,381,406	$1,358,190	$540,061
8	ACCUM. DEFERRED TAXES	($1,062,992,832)	($577,093,568)	($470,076,111)	($4,073,726)	($8,024,201)	($3,725,226)
9	REGULATORY ASSETS	($93,364,564)	($49,127,146)	($44,234,787)	($193,572)	$145,136	$45,805
10	DECOMMISSIONING FUND	$285,856,167	$135,532,339	$145,260,236	$3,481,853	$1,280,428	$301,312
11	GAIN FROM DISP. OF PLANT	($46,360,307)	($24,074,114)	($22,075,210)	($210,983)	$0	$0
12	MISCELLANEOUS DEFERRED DEBITS	$39,464,108	$24,492,979	$14,258,861	$213,053	$348,203	$151,013
13	CUSTOMER ADVANCES	($59,807,000)	($43,338,952)	($13,858,832)	($2,407,716)	($201,500)	$0
14	CUSTOMER DEPOSITS	($54,860,000)	($29,075,800)	($24,737,362)	($564,674)	($330,038)	($152,126)
15	PROFORMA ADJUSTMENTS	$5,559,077	$1,390,835	$4,896,294	$3,888	($506,633)	($225,307)
16	TOTAL RATE BASE	$4,401,129,682	$2,453,935,289	$1,847,777,081	$25,198,732	$50,817,350	$23,401,231
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$2,066,144,726	$1,058,729,739	$967,398,538	$20,966,540	$12,913,053	$6,136,856
20	PROFORMA TO REVENUES FROM RATES	$66,084,186	$33,316,369	$32,153,204	($102,439)	$431,212	$285,840
21	OTHER ELECTRIC REVENUE	$458,779,789	$219,766,673	$228,765,717	$5,331,054	$4,246,772	$669,573
22	TOTAL OPERATING REVENUES	$2,591,008,701	$1,311,812,781	$1,228,317,459	$26,195,155	$17,591,037	$7,092,269
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$2,302,448,767	$1,142,667,874	$1,118,136,205	$25,236,754	$13,153,614	$3,254,320
26	ADMINISTRATIVE & GENERAL	$132,687,128	$81,444,413	$48,487,580	$880,883	$1,303,165	$571,087
27	DEPRECIATION & AMORT EXPENSE	$285,758,990	$159,732,184	$119,779,814	$1,842,301	$3,034,821	$1,369,871
28	AMORTIZATION ON GAIN	($6,528,055)	($3,299,367)	($3,172,586)	($45,007)	($8,981)	($2,113)
29	REGULATORY ASSETS	($2,203,510)	($1,144,245)	($1,049,237)	($10,028)	$0	$0
30	PROFORMA ADJUSTMENTS	($531,955,639)	($250,025,162)	($270,354,853)	($7,436,666)	($3,257,110)	($881,848)
31	TAXES OTHER THAN INCOME	$116,332,654	$65,666,581	$47,839,518	$739,434	$1,432,424	$654,697
32	INCOME TAX	$64,509,260	$18,934,446	$43,202,562	$1,565,617	$246,173	$560,462
33	TOTAL OPERATING EXPENSES	$2,361,049,596	$1,213,976,724	$1,102,869,003	$22,773,289	$15,904,105	$5,526,475
34							
35	OPERATING INCOME	$229,959,105	$97,836,057	$125,448,456	$3,421,866	$1,686,932	$1,565,794
36							
37	RETURN	$229,959,105	$97,836,057	$125,448,456	$3,421,866	$1,686,932	$1,565,794
38							
39	RATE OF RETURN (PRESENT)	5.23%	3.99%	6.79%	13.58%	3.32%	6.69%
40							
41	INDEX RATE OF RETURN (PRESENT)	1.01	0.77	1.32	2.63	0.64	1.30

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

Line No.	Description	TOTAL GENERAL SVC (10)	E-20 (Church Rate) (11)	E-30, E-32 (0 - 20 kW) (12)	E-32 (21 - 100 kW) (13)	E-32 (101 - 400 kW) (14)	E-32 (401 - 999 kW) (15)	E-32 (1,000 + kW) (16)	E-34 (17)	E-35 (18)
		<---------- GE-2 ---------->								
	SUMMARY OF RESULTS									
1	DEVELOPMENT OF RATE BASE									
2	ELECTRIC PLANT IN SERVICE	$3,708,391,092	$13,156,897	$713,155,581	$919,510,111	$826,034,200	$457,251,865	$358,405,105	$234,275,856	$186,601,479
3	GENERAL & INTANGIBLE PLANT	$240,421,594	$800,809	$52,580,861	$57,265,737	$49,297,753	$28,539,088	$22,452,629	$15,147,299	$14,337,418
4	LESS: RESERVE FOR DEPRECIATION	($1,556,766,586)	($4,998,590)	($279,217,143)	($374,393,106)	($351,525,773)	($200,022,369)	($153,944,888)	($102,825,889)	($89,838,828)
5	OTHER DEFERRED CREDITS	($204,189,689)	($504,986)	($33,881,944)	($46,623,347)	($45,546,063)	($26,468,874)	($21,907,125)	($14,852,010)	($14,405,339)
6	WORKING CASH	($11,971,511)	($41,526)	($2,053,804)	($2,885,084)	($2,721,723)	($1,551,419)	($1,227,267)	($811,036)	($679,652)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$82,459,091	$266,994	$12,148,857	$18,052,533	$18,725,412	$11,772,505	$8,953,712	$6,220,412	$6,318,665
8	ACCUM. DEFERRED TAXES	($470,076,111)	($1,567,481)	($90,308,700)	($116,045,894)	($103,935,236)	($57,118,420)	($46,381,008)	($30,261,289)	($24,458,083)
9	REGULATORY ASSETS	($44,234,787)	($87,353)	($8,279,471)	($10,756,114)	($9,709,906)	($5,095,187)	($4,641,924)	($3,022,835)	($2,641,997)
10	DECOMMISSIONING FUND	$145,260,236	$396,517	$14,406,781	$27,667,366	$34,001,927	$23,592,112	$17,516,133	$12,742,045	$14,937,355
11	GAIN FROM DISP. OF PLANT	($22,075,210)	($50,436)	($3,849,143)	($5,211,280)	($4,923,522)	($2,721,500)	($2,342,339)	($1,557,044)	($1,419,946)
12	MISCELLANEOUS DEFERRED DEBITS	$14,258,861	$47,424	$3,115,471	$3,396,159	$2,924,948	$1,692,897	$1,332,470	$898,858	$850,635
13	CUSTOMER ADVANCES	($13,858,832)	($47,917)	($2,038,227)	($3,125,023)	($3,289,801)	($2,093,348)	($1,348,834)	($955,473)	($960,209)
14	CUSTOMER DEPOSITS	($24,737,362)	($85,530)	($3,638,139)	($5,578,020)	($5,872,139)	($3,736,527)	($2,407,606)	($1,705,475)	($1,713,927)
15	PROFORMA ADJUSTMENTS	$4,896,294	($18,976)	$625,766	$1,062,131	$1,129,685	$500,955	$671,708	$445,264	$479,760
16	TOTAL RATE BASE	$1,847,777,081	$7,265,846	$372,766,746	$462,336,170	$404,589,762	$224,541,777	$175,130,767	$113,738,683	$87,407,331
17										
18	DEVELOPMENT OF RETURN									
19	REVENUES FROM RATES	$967,398,538	$3,344,799	$142,275,889	$218,138,380	$229,640,445	$146,123,538	$94,153,699	$66,695,622	$67,026,166
20	PROFORMA TO REVENUES FROM RATES	$32,153,204	$250,921	$9,919,877	$3,997,949	$15,079,785	$1,059,540	$1,018,113	$135,964	$691,055
21	OTHER ELECTRIC REVENUE	$228,765,717	$651,493	$24,010,043	$44,323,121	$53,361,026	$36,720,311	$27,207,155	$19,724,984	$22,767,584
22	TOTAL OPERATING REVENUES	$1,228,317,459	$4,247,213	$176,205,809	$266,459,450	$298,081,256	$183,903,389	$122,378,967	$86,556,570	$90,484,805
23										
24	OPERATING EXPENSES									
25	OPERATION & MAINTENANCE	$1,118,136,205	$3,103,839	$129,308,205	$220,897,730	$258,190,478	$174,469,857	$130,669,186	$94,134,754	$107,362,156
26	ADMINISTRATIVE & GENERAL	$48,487,580	$168,558	$10,453,288	$11,676,787	$10,128,362	$5,827,742	$4,474,610	$3,006,658	$2,751,576
27	DEPRECIATION & AMORT EXPENSE	$119,779,814	$441,855	$23,085,668	$29,369,824	$26,524,854	$15,018,891	$11,487,621	$7,583,550	$6,267,552
28	AMORTIZATION ON GAIN	($3,172,586)	($7,702)	($476,581)	($702,487)	($718,845)	($430,995)	($351,385)	($241,284)	($243,307)
29	REGULATORY ASSETS	($1,049,237)	($2,397)	($182,950)	($247,693)	($234,016)	($129,353)	($111,332)	($74,006)	($67,490)
30	PROFORMA ADJUSTMENTS	($270,354,853)	($746,260)	($22,507,384)	($51,667,688)	($58,643,184)	($46,990,354)	($34,129,207)	($25,759,890)	($29,910,887)
31	TAXES OTHER THAN INCOME	$47,839,518	$190,638	$9,622,639	$12,021,204	$10,585,525	$5,888,989	$4,435,255	$2,889,635	$2,205,634
32	INCOME TAX	$43,202,562	$329,545	$6,181,818	$11,884,902	$14,993,575	$8,772,541	$433,470	$706,553	($99,844)
33	TOTAL OPERATING EXPENSES	$1,102,869,003	$3,478,075	$155,484,704	$233,232,580	$260,826,749	$162,427,317	$116,908,219	$82,245,969	$88,265,390
34										
35	OPERATING INCOME	$125,448,456	$769,138	$20,721,105	$33,226,871	$37,254,507	$21,476,071	$5,470,748	$4,310,600	$2,219,415
36										
37	RETURN	$125,448,456	$769,138	$20,721,105	$33,226,871	$37,254,507	$21,476,071	$5,470,748	$4,310,600	$2,219,415
38										
39	RATE OF RETURN (PRESENT)	6.79%	10.59%	5.56%	7.19%	9.21%	9.56%	3.12%	3.79%	2.54%
40										
41	INDEX RATE OF RETURN (PRESENT)	1.32	2.05	1.08	1.39	1.79	1.86	0.61	0.74	0.49

STAFF REVENUE REQUIREMENT - 4CP ALLOCATION
FOR COMPARISON ONLY

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

Line No.	Description	TOTAL RESIDENTIAL (19)	RESIDENTIAL E-10 (20)	RESIDENTIAL E-12 (21)	RESIDENTIAL EC-1 (22)	RESIDENTIAL ET-1 (23)	RESIDENTIAL ECT-1 (24)
		<---------- GE-3 ---------->					
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$4,681,780,206	$281,733,273	$1,463,863,508	$155,716,852	$2,319,963,476	$460,503,097
3	GENERAL & INTANGIBLE PLANT	$413,695,677	$27,609,575	$148,850,621	$12,375,982	$190,265,394	$34,594,106
4	LESS: RESERVE FOR DEPRECIATION	($1,928,646,856)	($121,994,885)	($606,018,515)	($66,501,787)	($945,187,421)	($188,944,248)
5	OTHER DEFERRED CREDITS	($230,684,114)	($13,825,950)	($71,463,902)	($7,843,378)	($113,766,401)	($23,784,483)
6	WORKING CASH	($12,831,079)	($723,129)	($3,720,280)	($447,338)	($6,554,955)	($1,385,377)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$91,914,881	$5,685,919	$28,611,532	$3,209,242	$44,893,772	$9,514,416
8	ACCUM. DEFERRED TAXES	($577,093,568)	($33,820,196)	($178,907,141)	($19,024,386)	($287,506,652)	($57,835,194)
9	REGULATORY ASSETS	($49,127,146)	($2,735,750)	($14,707,336)	($1,630,247)	($24,868,511)	($5,185,302)
10	DECOMMISSIONING FUND	$135,532,339	$8,749,151	$41,051,666	$5,176,484	$65,386,973	$15,168,064
11	GAIN FROM DISP. OF PLANT	($24,074,114)	($1,381,773)	($7,212,965)	($820,405)	($12,112,000)	($2,546,971)
12	MISCELLANEOUS DEFERRED DEBITS	$24,492,979	$1,633,948	$8,808,332	$733,029	$11,267,889	$2,049,781
13	CUSTOMER ADVANCES	($43,338,952)	($2,879,259)	($14,760,504)	($1,501,737)	($20,077,388)	($4,120,063)
14	CUSTOMER DEPOSITS	($29,075,800)	($1,931,675)	($9,902,719)	($1,007,505)	($13,469,779)	($2,764,122)
15	PROFORMA ADJUSTMENTS	$1,390,835	($12,352)	($102,392)	$79,534	$1,061,327	$364,718
16	TOTAL RATE BASE	$2,453,935,289	$146,106,897	$784,389,906	$78,514,340	$1,209,295,724	$235,628,421
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$1,058,729,739	$70,337,587	$360,585,198	$36,686,029	$490,471,664	$100,649,261
20	PROFORMA TO REVENUES FROM RATES	$33,316,369	($2,061,923)	$12,766,411	($1,178,134)	$21,464,438	$2,325,577
21	OTHER ELECTRIC REVENUE	$219,766,673	$14,126,959	$66,978,163	$8,281,280	$106,120,557	$24,259,714
22	TOTAL OPERATING REVENUES	$1,311,812,781	$82,402,623	$440,329,772	$43,789,175	$618,056,659	$127,234,552
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$1,142,667,874	$73,964,084	$357,077,451	$41,906,267	$547,806,416	$121,913,655
26	ADMINISTRATIVE & GENERAL	$81,444,413	$5,435,590	$28,926,720	$2,483,640	$37,721,841	$6,876,622
27	DEPRECIATION & AMORT EXPENSE	$159,732,184	$9,911,645	$51,449,950	$5,249,433	$77,904,622	$15,216,534
28	AMORTIZATION ON GAIN	($3,299,367)	($196,177)	($991,655)	($116,349)	($1,640,307)	($354,879)
29	REGULATORY ASSETS	($1,144,245)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)
30	PROFORMA ADJUSTMENTS	($250,025,162)	($17,982,015)	($75,360,844)	($10,504,709)	($117,930,786)	($28,246,808)
31	TAXES OTHER THAN INCOME	$65,666,581	$4,071,767	$21,173,025	$2,145,953	$32,090,164	$6,185,673
32	INCOME TAX	$18,934,446	$1,242,490	$13,701,397	$214,854	$3,942,033	($166,327)
33	TOTAL OPERATING EXPENSES	$1,213,976,724	$76,381,709	$395,633,210	$41,340,094	$579,318,298	$121,303,412
34							
35	OPERATING INCOME	$97,836,057	$6,020,914	$44,696,561	$2,449,080	$38,738,361	$5,931,139
36							
37	RETURN	$97,836,057	$6,020,914	$44,696,561	$2,449,080	$38,738,361	$5,931,139
38							
39	RATE OF RETURN (PRESENT)	3.99%	4.12%	5.70%	3.12%	3.20%	2.52%
40							
41	INDEX RATE OF RETURN (PRESENT)	0.77	0.80	1.11	0.61	0.62	0.49

EXHIBIT
S-8
admitted

BEFORE THE

ARIZONA CORPORATION COMMISSION

APPLICATION OF ARIZONA PUBLIC SERVICE CO. FOR AN INCREASE IN ELECTRIC RATES	))))	DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY AND EXHIBIT

OF

DAVID C. PARCELL

ON BEHALF OF THE

COMMISSION STAFF

AUGUST 18, 2006

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BEFORE THE ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY AND EXHIBIT

OF

DAVID C. PARCELL

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is David C. Parcell. I am Executive Vice President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. The large majority of my consulting experience has involved the provision of cost of capital testimony in public utility ratemaking proceedings. I have previously testified in about 375 utility proceedings before some 35 regulatory agencies in the United States and Canada. Schedule 1 contains a more complete description of my education and professional experience.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the Commission Staff to evaluate the cost of capital aspects of the current filing of Arizona Public Service Co. ("APS" or "Company"). Based on my analyses, I am making a recommendation of the current cost of capital for APS. In addition, since APS is a subsidiary of Pinnacle West Capital Corp. ("PWC"), I am also evaluating this entity in my analyses.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 15. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A. My overall cost of capital recommendation for APS is follows:

	Percent	Cost	Return
Long-Term Debt	45.5%	5.41%	2.46%
Common Equity	54.5%	10.25%	2.59%
Total	100.00%		8.05%

APS's application requests a return on equity of 11.5 percent and a total cost of capital of 8.73%.

Q. PLEASE SUMMARIZE YOUR ANALYSES AND CONCLUSIONS.

A. This proceeding is concerned with APS's regulated electric utility operations in Arizona. My analyses are concerned with APS's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. APS's proposed capital structure is its adjusted September 30, 2005 capital structure ratios of 45.5 percent long-term debt and 54.5 percent common equity. I have adopted these capital structure ratios in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of long-term debt. I have used the 5.41 percent cost of long-term debt proposed by APS.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for APS. I applied each of these methodologies to two proxy groups: 1) a group of comparison electric utilities with similar operating and risk characteristics to APS and

PWC; and, 2) and the group of proxy electric companies analyzed by Company witness Avera. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9½-10%
Capital Asset Pricing Model	10½-10¾%
Comparable Earnings	10%

Based upon these findings, I conclude that the cost of common equity for APS is a range of 9½ percent to 10¾ percent, with an approximate mid-point of 10.25 percent. I recommend a cost of equity for APS of 10.25 percent.

Combining these three steps into weighted costs of capital results in an overall rate of return of 8.05 percent.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. WHAT IS YOUR UNDERSTANDING OF THE ECONOMIC AND LEGAL PRINCIPLES WHICH UNDERLIE THE CONCEPT OF A FAIR RATE OF RETURN FOR A REGULATED UTILITY?

A. Cost of service rates for regulated public utilities have traditionally been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers. The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, the fair rate of return is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably, as I have done in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to incorporate the financial concepts of financial integrity, capital attraction, and comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two U.S. Supreme Court decisions are universally cited as

providing the standards for a fair rate of return. The first is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of a fair and enlightened judgment**, having regard to all relevant facts. A **public utility** is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. **[Emphasis added.]**

Based on my understanding, this decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a **balancing** of the **investor** and **consumer interests**. . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the

> enterprise, so as to **maintain its credit** and to **attract capital. [Emphasis added.]**

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

Three economic and financial parameters identified in the Bluefield and Hope decisions – comparable earnings, financial integrity, and capital attraction – reflect the economic criteria encompassed in the "opportunity cost" principle of economics, which holds that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. Nevertheless, the economic principles that I utilize in developing my recommendations are appropriate for determining APS's cost of capital in this proceeding.

Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods

(or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE COST OF COMMON EQUITY?

A. I have utilized three methodologies to determine APS's cost of common equity: the DCF, CAPM, and CE methods. The results of each of these methodologies will be described in my testimony.

IV. GENERAL ECONOMIC CONDITIONS

Q. WHAT IS THE IMPORTANCE OF ECONOMIC AND FINANCIAL CONDITIONS IN DETERMINING THE COST OF CAPITAL?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by economic and financial conditions. At any given time, each of the following factors has a direct and significant influence on the costs of capital: the level of economic activity, the stage of the business cycle, the level of inflation, and expected economic conditions. My understanding is that this position is consistent with the Supreme Court Bluefield decision that noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE YOU EVALUATED IN YOUR ANALYSES?

A. I have examined several sets of economic statistics for the period 1975 to the present. I chose this period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to date, and thus makes it possible to assess changes in long-term trends. A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

Q. PLEASE DESCRIBE THE THREE PRIOR BUSINESS CYCLES AND THE MOST CURRENT CYCLE.

A. The most recent complete cycle began with an expansion in April of 1991 and ended in the fourth quarter of 2001, constituting a length of more than ten and one-half years. Following that, the economy slowed considerably in late 2000 and 2001 and was in a

recession during three quarters of 2001, notwithstanding the Federal Reserve lowering interest rates (i.e, Fed Funds rate) eleven times in 2001 (as well as twice in 2003) in an aggressive effort to create a soft landing and avoid a recession. The events of September 11, 2001 further damaged the U.S. economy.

This cycle and the two prior complete cycles cover the following periods:

Business Cycle	Expansion Period	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001

The expansion phase of the recent cycle well surpassed the average length of expansions in the post-World War II era (i.e., about five years). The 1982-1990 expansion (seven years, eight months) was the previous longest peacetime expansion of this era.

Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND FINANCIAL CONDITIONS AND THEIR IMPACT ON THE COSTS OF CAPITAL.

A. Schedule 2 shows several sets of economic data. Page 1 contains general macroeconomic statistics while pages 2 and 3 contain financial market statistics. Page 1 of Schedule 2 shows that growth in the initial stage of the current cycle was somewhat slower than the typical initial recovery period. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the unemployment rate.

The rate of inflation is also shown on page 1 of Schedule 2, reflected in the Consumer Price Index (CPI). The CPI rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 3.4 percent or lower. The 3.3 percent rate of inflation in 2005, along with a similar level for 2004, were slightly higher than the most recent years, but were both well below the levels of the past thirty years.

Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES?

A. Page 2 of Schedule 2 shows several series of interest rates. Rates rose sharply in 1975-1981 when the inflation rate was high and rising. Rates then fell substantially throughout the remainder of the 1980s and into the 1990s. During the recent business cycle, long-term rates remained relatively stable, in comparison to the prior cycles. Rates have increased somewhat over the past year, but nevertheless currently are generally lower than at any time during the prior three cycles.

This low level of interest rates, in conjunction with the apparent strengthening of the U.S. economy, may create an expectation that any near-term movement of interest rates will be upward. In fact, the Federal Reserve has, since the middle portion of 2004, increased short-term interest rates on seventeen occasions, although each by only a small 0.25 percent level, in an attempt to insure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the economic recovery to date has not resulted in a pronounced increase in long-term rates (in fact, the current level of Fed Funds is about the same as the level in existence when the series of reductions began in 2000) and, even if rates were to increase moderately, they would still remain well below historical levels.

Q. WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICES?

A. Page 3 of Schedule 2 shows several series of common stock prices and ratios. These indicate that share prices were basically stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s, as evidenced by the fact that the Dow Jones Industrial average (DJI) remained in the 800-900 range for eight years. On the other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a significant upward trend in stock prices as the DJI rose to over 11,000. Over the past five years, however, stock prices have been volatile.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DISCUSSION OF ECONOMIC AND FINANCIAL CONDITIONS?

A. It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models, such as the DCF, currently produce returns that are lower than was the case in prior years.

V. APS'S OPERATIONS AND RISKS

Q. PLEASE SUMMARIZE APS AND ITS OPERATIONS.

A. APS is a public utility that delivers electricity through its generation, transmission and distribution systems in Arizona. APS is the primary electric utility in Arizona and provides service to about one million customers in the state. APS is a subsidiary of PWC.

Q. PLEASE DESCRIBE PWC.

A. PWC is a holding company whose major subsidiary is APS. Other subsidiaries of PWC are: SunCor (engaged in real estate development and investment activities) and APS Energy Services (provides competitive energy services and products in the western U.S).

Q. WHAT ARE PWC'S BUSINESS SEGMENT RATIOS?

A. This is shown on Schedule 3 for the years 2002-2005. As indicated, the "Regulated Electricity" segment has accounted for the following percentages:

	2002	2003	2004	2005
Operating Revenue	77.5%	71.7%	71.9%	74.9%
Operating Income	82.5%	75.6%	61.5%	74.9%
Net Income	114.1%	70.5%	62.6%	94.9%
Total Assets	89.6%	91.9%	87.6%	85.9%

This indicates that the electric regulated operations (i.e., APS) of PWC account for the vast majority of income for the consolidated enterprise. It is also apparent that the regulated operations are the most profitable.

Q. WHAT ARE THE CURRENT BOND RATINGS OF APS?

A. The present bond ratings of APS are as follows:

Moody's	Baa2
Standard & Poor's	BBB-
Fitch	BBB-

Q. WHAT HAVE BEEN THE TRENDS IN APS'S AND PWC'S BOND RATINGS?

A. This is shown on Schedule 4, which indicates that APS has had triple B ratings since 2000. It is also apparent that the ratings of APS have declined in 2006. Finally, it is evident that APS has maintained higher ratings than PWC.

Q. WHAT ARE THE STATED REASONS FOR THE CURRENT RATINGS OF APS AND THE REASONS FOR THE DECLINES IN 2006?

A. It is apparent that APS is viewed as a utility characterized by a strong and growing service area and strong rating metrics. On the other hand, a primary rating issue for the Company, and a significant stated reason for the recent downgrades, is the difficulties the Company has had in recovering power costs.

Standard &Poor's (S&P) recently stated, in a February 15, 2006 report on APS:

> Arizona Public Service's (APS) 'BBB-' corporate credit rating is based on the consolidated credit quality of Pinnacle West Capital Corp. (PWCC), of which APS is the principal subsidiary. APS is a vertically integrated investor-owned utility that provides retail electric service to about one million customers throughout Arizona, including about half of the Phoenix MSA.
>
> . . .
>
> A strong and diversified Phoenix economy has fueled significant utility growth, and a large residential base that accounted for 50% of APS' retail electric sales in 2004 provides stability. On the other hand, regulatory risk has increased, reflected in uncertainty related to the recovery of rising fuel and purchased power costs and in APS' significant pending general rate case, in which the company is requesting a 21.3%, or $453.9 million, rate increase.
>
> Regulatory uncertainty is exacerbated by the establishment in 2004 of a weak power supply adjuster (PSA) that exposes the utility to potential cash flow volatility.

These points were also cited by Moody's Investors Service (Moody's) in an April 27, 2006 report announcing the downgrades of APS:

> Moody's Investors Service downgraded the long-term ratings of Pinnacle West Capital Corporation (Pinnacle: Issuer Rating to Baa3 from Baa2) and its subsidiaries Arizona Public Service Company (APS: senior unsecured to Baa2 from Baa1).
>
> . . .
>
> The rating downgrades reflect deterioration in key financial metrics as a result of increased fuel and purchased power costs that APS is unable to recover on a timely basis.

Finally, Fitch Ratings (Fitch) made the following comments in a May 5, 2006 report:

> PNW and APS's ratings and Outlook consider the utility's rapidly growing electric service territory and solid credit metrics.
>
> . . .
>
> The ACC's supportive response to the company's request for emergency rate relief authorizes a $140 million interim rate increase to recover deferred power supply costs, subject to a final ruling in APS's general rate case.
>
> Prior rate decisions have been less constructive to the credit profile of APS. The January 2006 downgrade of APS by Fitch Ratings was triggered by rejection of the company's surcharge request for recovery of deferred power supply costs, and adoption of PSA provisions by the commission that are less favorable than had been anticipated by Fitch in its previous ratings.

Q. HOW DO THE BOND RATINGS OF APS COMPARE TO ELECTRIC UTILITIES?

A. As I indicated in a previous answer, APS has triple B bond ratings, which are investment grade (i.e., triple B or above). Of the 65 electric utilities and combination gas and electric utilities covered by AUS Utilities Reports, the following bond ratings currently exist:

	Moody's	S&P
Aa/AA	3	5
A/A	24	20
Baa/BBB	29	35
Ba/BB or Below	3	3
Not Rated	6	6

This comparison indicates that APS' ratings are in the largest rating category of electric utilities.

Q. YOU HAVE CITED A PERCEIVED HIGHER LEVEL OF RISK ATTRIBUTED TO APS RESULTING FROM ITS RECENT DIFFICULTIES ASSOCIATED WITH THE RECOVERY OF ITS POWER COSTS. ARE THERE ANY FACTORS IN THE PRESENT CASE THAT MAY IMPACT THIS?

A. Yes, there are. It is my understanding that other Commission Staff witnesses are making recommendations in this proceeding that, if adopted by the Commission, will have the effect of reducing APS's exposure to the collection and timing of its power costs. In particular, Staff witness Antonuk addresses the alternative of using a forward-year forecast as the basis of setting the amount of the PSA. If the Commission adopts that alternative, the required cost of equity for APS could be less than it would in the absence of its adoption.

VI. CAPITAL STRUCTURE AND COSTS OF DEBT AND PREFERRED STOCK

Q. WHAT IS THE IMPORTANCE OF DETERMINING A PROPER CAPITAL STRUCTURE IN A REGULATORY FRAMEWORK?

A. A utility's capital structure is important since the concept of rate base - rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain the capital costs of the company. The rate base - rate of return concept recognizes the assets which are employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) which are used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case since common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and (3) causes the most controversy since its cost cannot be precisely determined.

Q. HOW IS APS FINANCED?

A. APS's common stock is owned by PWC. As a result, APS obtains all of its equity funding from PWC. APS obtains its own debt stock financing.

Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTURE OF APS?

A. I have examined the five year historic (2001-2005) capital structure ratios of APS and PWC. These are shown on Schedule 5.

I have summarized below the common equity ratios for APS and PWC for the last five years:

	APS		PWC	
	Inc'l S-T Debt	Exc'l S-T Debt	Inc'l S-T Debt	Exc'l S-T Debt
2001	48.9%	50.9%	43.8%	47.2%
2002	49.3%	49.3%	45.2%	47.0%
2003	45.7%	45.7%	45.4%	46.0%
2004	45.1%	45.1%	47.4%	48.0%
2005	53.8%	53.8%	53.2%	53.4%

This indicates that APS and PWC have generally had rising common equity ratios since 2001.

Q. HOW DO THESE CAPITAL STRUCTURE RATIOS COMPARE TO ELECTRIC UTILITIES IN GENERAL?

A. This is shown on Schedule 6. This indicates that the average common equity ratios for the two groups of electric utilities are below those of APS over the past five years. This is indicative of a lower degree of financial risk for APS.

Q. WHAT CAPITAL STRUCTURE RATIO HAS APS REQUESTED IN THIS PROCEEDING?

A. The Company requests use of the following capital structure:

Capital Item	Percentage
Long-term Debt	45.5%
Common Equity	54.5%

According to the Company's application these are the "adjusted" September 30, 2005 capital structure ratios of APS.

Q. WHAT CAPITAL STRUCTURE DO YOU PROPOSE TO USE IN THIS PROCEEDING?

A. I have adopted the adjusted test period capital structure of APS, as proposed by the Company. I do this since the proposed capital structure appears to be the actual capital structure. I note, on the other hand, that this capital structure contains a higher equity ratio than both electric utilities in general and the proxy groups in particular. As such, the APS capital structure, as proposed and as accepted by me, reflects a lower degree of financial risk than both the proxy groups and electric utilities.

Q. WHAT IS THE COST OF LONG-TERM DEBT?

A. The Company's filing cites a long-term debt cost of 5.41 percent. I use this cost rate in my cost of capital analyses.

Q. CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME DEGREE OF PRECISION AS THE COSTS OF DEBT AND PREFERRED STOCK?

A. No. The cost rates of debt are largely determined by interest payments, issue prices, and related expenses. Even though alternative methodologies exist for determining the embedded cost rate, the cost rate for debt is generally agreed to, at least within a relatively small range.

The cost of common equity, on the other hand, is not susceptible of specific measurement, primarily because this cost is an opportunity cost. There are, however, several models that can be employed to estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and CE - are developed in the following sections of my testimony.

VII. SELECTION OF COMPARISON GROUPS

Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR APS?

A. APS is not a publicly traded company; rather, it is a subsidiary of PWC. As a result, it is not possible to conduct direct analyses of the cost of common equity for APS. It is possible to conduct studies of PWC's cost of equity; however, the diversified nature of this company's operations indicate that it is not an adequate proxy, standing alone, for the cost of equity for APS. As a result, it is useful to also analyze groups of comparison or "proxy" companies as a substitute for APS to determine its cost of common equity.

The most frequently used alternative is to select a group of comparison utilities. I have examined two such groups for comparison to APS. I have first selected one group of electric utilities similar to APS and PWC using the criteria listed on Schedule 7 These criteria are as follows:

(1) Market capitalization of $1 billion to $8 billion;

(2) Electric revenues 50% or greater;

(3) Common equity ratio 40% or greater;

(4) Value Line Safety of 1, 2 or 3;

(5) S&P and Moody's bond ratings of Triple B; and,

(6) S&P stock ranking of B, B+, or A-.

Second, I have further conducted studies of the cost of equity for the proxy group of electric utilities selected by APS's witness William Avera.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DISCOUNTED CASH FLOW MODEL?

A. The discounted cash flow (DCF) model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. When applied to common stocks, the dividend discount model describes the value of a stock as follows:

$$P = \frac{D_1}{(1+K_1)} + \frac{D_2}{(1+K_2)^2} + \ldots + \frac{D_n}{(1+K_n)^n} = \sum_{i=1}^{n} \frac{D_t}{(1+K)^t}$$

where: P = current price

D_1 = dividends paid in period 1, etc.

K_1 = discount rate in period 1, etc.

n = infinity

This relationship can be simplified if dividends are assumed to grow at a constant rate of g. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, the price of a stock is determined as follows:

$$P = \frac{D}{(K-g)}$$

where: P = current price

D = current dividend rate

K = discount rate (cost of capital)

g = constant rate of expected growth

This equation can be solved for K (i.e., the cost of capital) to yield the following formula:

$$K = \frac{D}{P} + g$$

This formula essentially states that the return expected or required by investors is comprised of two factors: the yield (current income) and expected growth (future income).

Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy companies described in the previous section with several indicators of expected growth.

Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF EQUATION?

A. There are several methods which can be used for calculating the yield component. These methods generally differ in the manner in which the dividend rate is employed, i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate yield component is a quarterly compounding variant which is expressed as follows:

$$Yield = \frac{D_0(1 + 0.5g)}{P_0}$$

This yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each company for the most recent three month period (May-July, 2006). The D_0 is the current annualized dividend rate for each company.

Q. HOW HAVE YOU ESTIMATED THE GROWTH COMPONENT OF THE DCF EQUATION?

A. The growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the growth component is to reflect the growth expected by investors which is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. A wide array of techniques exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2001-2005 (5-year average) earnings retention, or fundamental growth;
2. 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS);
3. 2006-2010 projections of earnings retention growth;
4. 2004-2010 projections of EPS, DPS, and BVPS; and
5. 5-year projections of EPS growth as reported in First Call (formerly I/B/E/S).

I believe this combination of growth indicators is a representative and appropriate set with which to estimate investor expectations of growth for the groups of natural gas companies.

Q. PLEASE DESCRIBE YOUR DCF CALCULATIONS.

A. Schedule 8 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield. Pages 2-3 show the growth rate for the groups of comparison companies. Page 4 shows the DCF calculations, which are presented on several bases: average, median, and high values. These results can be summarized as follows:

	Average	Median	High Value
Proxy Group	8.1%	8.4%	10.0%
Avera Group	8.8%	8.8%	9.6%

Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES?

A. Based upon my analyses, I believe a range of 9 percent to 10 percent represents the current DCF cost of equity for APS. The lower end (9 percent) approximates the upper values for the average/median results, while the upper end (10 percent) reflects the high value of the constant growth DCF calculations for the groups examined.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF THE CAPITAL ASSET PRICING MODEL.

A. The Capital Asset Pricing Model (CAPM) is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns.

Q. HOW IS THE CAPM DERIVED?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity

R_f = risk free rate

R_m = return on market

$\exists$ = beta

R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry, whereas the simple risk premium method does not.

Q. WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM YOUR CAPM ANALYSES?

A. I have performed CAPM analyses for the same groups of electric utilities evaluated in my DCF analyses.

Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE?

A. The first term of the CAPM is the risk free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In reality, there is no such thing as a truly riskless asset. In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. This follows since Treasury securities are default-free owing to the government's ability to print money and/or raise taxes to pay its debts.

Two types of Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds. I have performed CAPM calculations using the three-month average yield (May-July 2006) for 20-year U.S. Treasury bonds. Over this three-month period, these bonds had an average yield of 5.30 percent.

Q. WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?

A. I utilized the most current Value Line betas for each company in the groups of comparison electric companies. These are shown on Schedule 10 and are seen to be within a range of 0.70 to 1.20 (the beta for the entire market is 1.00).

Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM COMPONENT?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

Schedule 9 shows the return on equity for the S&P 500 group for the period 1978-2004 (all available years reported by S&P). The average return on equity for the S&P 500 group over the 1978-2004 period is 14.02 percent. This Schedule also indicates the annual yields on 20-Year U.S. Treasury bonds, as well as the annual differentials (i.e.,

risk premiums) between the S&P 500 and U.S. Treasury 20-Year bonds. Based upon these returns, I conclude that the risk premium is about 6 percent.

I have also considered the total returns for the S&P 500 group as well as for long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2005 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.5%	4.9%

I conclude from this that the expected risk premium is about 5.8 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 10 shows my CAPM calculations using this risk premium. The results are:

	Mean	Median
Proxy Group	10.4%	10.5%
Avera Group	10.7%	10.8%

Q. WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF EQUITY FOR THE GROUPS OF COMPARISON COMPANIES?

A. The CAPM results collectively indicate a cost of about 10½-10¾ percent for the two groups of proxy companies.

X. COMPARABLE EARNINGS ANALYSIS

Q. PLEASE DESCRIBE THE BASIS OF THE CE METHODOLOGY.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. HOW HAVE YOU EMPLOYED THE CE METHODOLOGY IN YOUR ANALYSIS OF APS's COMMON EQUITY COST?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation where a company is able to attract new equity capital without dilution (i.e., above book

value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my comparable earnings analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my comparable earnings analysis uses prospective returns and thus is not strictly backward looking.

Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR CE ANALYSIS?

A. My CE analysis considers the experienced equity returns of the proxy groups of companies for the historic period 1992-2005 (i.e., last 14 years) as well as the future periods 2006-2010. The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence by unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two historic periods – 2001-2005 (the last five years), and 1992-2001 (the most recent complete business cycle) – as well as the 2006-2010 projected period.

Q. PLEASE DESCRIBE YOUR CE ANALYSIS.

A. Schedule 11 and Schedule 12 contain summaries of experienced returns on equity for several groups of companies, while Schedule 13 presents a risk comparison of utilities versus unregulated firms.

Schedule 11 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

Group	Historic ROE	Historic M/B	Prospective ROE
Proxy Group	9.9-11.5%	139-141%	8.2-9.3%
Avera Group	11.3-11.7%	148-161%	9.9-10.4%

These results indicate that historic returns of 9.9-11.7 percent have been adequate to produce market-to-book ratios of 139-161 percent.

Furthermore, projected returns on equity for 2006, 2007 and 2009-2011 are within a range of 8.2 percent to 10.4 percent for the proxy groups. These relate to 2005 market-to-book ratios of 150 percent and higher.

Q. HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED FIRMS?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 12 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past thirteen years (i.e., 1992-2004). As this exhibit indicates, over the two periods this group's average earned returns ranged from 12.3-14.7 percent with market-to-book ratios ranging between 334-409 percent.

Q. HOW CAN THE ABOVE INFORMATION BE USED TO ESTIMATE THE COST OF EQUITY FOR APS?

A. The recent earnings of the utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for electric utilities, however, it is necessary to compare the risk levels of the electric utility industry with those of the competitive sector. I have done this in Schedule 13, which compares several risk indicators for the S&P 500 group and the proxy groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

1 **Q. WHAT RETURN ON EQUITY IS INDICATED BY THE CE ANALYSIS?**

2 A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis
3 indicates that the cost of equity for APS is no greater than 10 percent. Recent returns of
4 9.9-11.7 percent have resulted in market-to-book ratios of 139 and greater. Prospective
5 returns of 8.9-10.4 percent have been accompanied by market-to-book ratios of over 150
6 percent. As a result, it is apparent that returns below this level would result in market-to-
7 book ratios of well above 100 percent. An earned return of 10 percent or less should thus
8 result in a market-to-book ratio of at least 100 percent.

XI. RETURN ON EQUITY RECOMMENDATION

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR THREE COST OF EQUITY ANALYSES.

A. My three methodologies produce the following results for the proxy groups, as summarized below:

Discounted Cash Flow	9-10% (9.5% Mid-Point)
Capital Asset Pricing Model	10½-10¾%
Comparable Earnings	10%

My overall conclusion from these results is a range of 9½ percent to 10¾ percent, which focuses on the upper portions of the respective model results. My specific recommendation for APS is 10.25 percent, the approximate mid-point of this range.

XII. TOTAL COST OF CAPITAL

Q. WHAT IS THE TOTAL COST OF CAPITAL FOR APS?

A. Schedule 14 reflects the total cost of capital for the Company using the APS capital structure, the Company's proposed cost of long-term debt, and my common equity recommendation. The resulting total cost of capital is 8.05 percent.

Q. DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS FINANCIAL INTEGRITY?

A. Yes, it does. Schedule 15 shows the pre-tax coverage that would result if APS earned the mid-point of my cost of capital recommendation. As the results indicate, the mid-point of my recommended range would produce a coverage level that is above the benchmark range for an A rated utility. In addition, the debt ratio is consistent with that of an A rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. HAVE YOU RECEIVED THE TESTIMONY OF APS' COST OF EQUITY WITNESS?

A. Yes, I have. Dr. William E. Avera is the Company's cost of equity witness.

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF DR. AVERA'S COST OF EQUITY ANALYSES AND RECOMMENDATION.

A. Dr. Avera's cost of equity findings can be summarized as follows:

DCF	9.0%
Risk Premium	
Authorized Returns	10.7-11.4%
Realized Rates of Return	9.8-11.0%
CAPM	
Forward-Looking	12.5-12.6%
Historical	10.9-11.9%
Comparable Earnings	11.0-12.0%
Cost of Equity-Proxy Group	10.8-11.8%
Flotation Cost Allowance	0.2%
Rate of Return-Proxy Group	11.0-12.0%
Recommendation	11.5%

Q. DO YOU HAVE ANY COMMENTS CONCERNING DR. AVERA'S DCF ANALYSES AND CONCLUSIONS?

A. Yes, I do. Dr. Avera's DCF analyses contain a 9.0 percent conclusion, which matches the bottom end of my DCF range of 9 percent to 10 percent. However, he apparently gives this methodology little or no weight in his 11 percent to 12 percent

recommendation for APS. I believe this is a deficiency in his analyses, in that he has virtually ignored the results of the most commonly-used cost of capital methodology.

Q. DO YOU HAVE ANY COMMENTS ABOUT DR. AVERA'S "SURVEYS OF ALLOWED RATES OF RETURN" RISK PREMIUM ANALYSIS?

A. Yes, I do. This analysis simply compares authorized returns on common equity for electric utilities with the yield on public utility bonds for the period 1974-2004 (average differential of 3.17 percent). He then performs a regression analysis to reflect his belief "that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates." His conclusion is that a 4.93 percent equity risk premium is necessary for the "current" 5.51 percent yield (as of August, 2005) on BBB rated public utility bonds.

This 4.93 percent spread is clearly excessive. A review of Dr. Avera's Schedule WEA-4 indicates that the actual "risk premium" did not reach 4.93 percent in any of the thirty-one years covered in the 1974-2004 period. If we focus on more recent periods (e.g., last 10 years), the average "spread" is about 3.8 percent. If this were combined with the 6.7 percent (June, 2006) yield on BBB rated utility debt, the result is 10.4 percent.

This example exposes the fallacy of comparing authorized returns with bond yields. The period examined, regression results, and many other factors impact the results. It seems very doubtful that regulatory commissions, including this Commission, would want to set rates of return based upon the Commissions' decisions over vastly different circumstances.

Q. WHAT ARE YOUR COMMENTS CONCERNING DR. AVERA'S "REALIZED RATES OF RETURN" RISK PREMIUM ANALYSIS?

A. This approach compares realized returns" (capital gains/losses plus dividends) for the S&P Electric Utilities groups and A rated public utility bond yields over the 1946-2004 period. The resulting 4.04 percent average "equity risk premium" is added to his 7.0 percent yield on triple-B public utility bonds to yield an 11.0 percent return.

I disagree conceptually with this type of analysis for many of the same reasons described in my response to Dr. Avera's allowed rates of return risk premium analysis; changing trends in capital costs, sensitivity to period selected, etc.

Q. WHAT ARE YOUR COMMENTS REGARDING DR. AVERA'S CAPM RISK PREMIUM ANALYSIS?

A. Dr. Avera's CAPM uses the following inputs.

Market rate of return	13.1%
Risk free rate	4.5%
Beta	0.89

My primary disagreement is with his 13.5 percent market return and resulting 9.0 percent risk premium (i.e., 13.5% minus 4.5%). I have previously indicated that risk premium associated with the S&P 500 composite group (as used by Dr. Avera in his CAPM) has been about 5.8 percent. There is no legitimate reason, therefore, to expect this group to achieve a 9 percent risk premium over the longer term.

Use of a more reasonable expected market return, such as that contained in my CAPM analyses, and more recent yield on risk-free rate, produces a CAPM result similar to my 10½ - 10¾ percent conclusion.

Q. DO YOU HAVE ANY COMMENTS ABOUT DR. AVERA'S COMPARABLE EARNINGS ANALYSIS?

A. Yes, I do. Dr. Avera's comparable earnings analysis is based on his observations that Value Line projections of electric utility returns on equity (as of September, 2005) were 10.5 percent to 11.0 percent. I note that my Schedule 11 indicates that Value Line currently projects returns on equity for his proxy group of 9.9 percent (2009-2011) to 10.4 percent (2006). These projections are consistent with my 9½ percent to 11¾ percent recommendation.

Q. WHAT COMMENTS DO YOU HAVE CONCERNING DR. AVERA'S FLOTATION COST ADJUSTMENT?

A. Dr. Avera increases each of his cost of equity estimates by 20 basis points as a flotation cost adjustment. There is no need to make a flotation adjustment, as Dr. Avera recommends. A utility should only be allowed to recover from ratepayers its actual, quantifiable levels of issuance costs. Neither Dr. Avera nor APS has made any demonstration that the company has incurred any issuance costs. In addition, as my Schedule 11 reflects, his electricity distribution group has 2005 market-to-book ratios of 162 percent. To make a market-to-book adjustment for companies whose market-to-book ratio already exceeds 162 percent is unnecessary and inappropriate, since any common stock issuance would actually increase to book value of existing stockholders. I also note that the revenue requirement associated with Dr. Avera's flotation cost adjustment is nearly $8 million annually (Source: Response to TAI-1-13). This is clearly an excessive level of flotation costs for ratepayers to incur.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
EXECUTIVE VICE PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

1995-Present	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies.

Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's

Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association,
Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
		1975 - 1982 Cycle			
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
		1983 - 1991 Cycle			
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
		1992 - 2001 Cycle			
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.2%	5.4%	3.3%	2.8%
1997	4.5%	7.3%	4.9%	1.7%	-1.2%
1998	4.2%	5.9%	4.5%	1.6%	0.0%
1999	4.5%	4.5%	4.2%	2.7%	2.9%
2000	3.7%	4.3%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
		Current Cycle			
2002	1.6%	0.1%	5.8%	2.4%	1.2%
2003	2.7%	0.6%	6.0%	1.9%	4.0%
2004	4.2%	4.1%	5.5%	3.3%	4.2%
2005	3.5%	3.3%	5.1%	3.4%	5.4%
2004					
1st Qtr.	4.3%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	4.0%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	3.3%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.8%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.2%	1.6%
3rd Qtr.	4.1%	2.7%	5.0%	9.6%	10.8%
4th Qtr.	1.7%	3.1%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.40%
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	5.42%
4th Qtr.	1,230.47	2,178.67	10,615.78	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

PINNACLE WEST CAPITAL CORP.
SEGMENT FINANCIAL INFORMATION
2002 - 2005
($millions)

Segment	Operating Revenue	Income From Continuing Operations	Net Income	Total Assets
		2002		
Regulated Electricity	$1,890 77.5%	$170 82.5%	$170 114.1%	$8,185 89.6%
Real Estate	$201 8.2%	$10 4.9%	$19 12.8%	$504 5.5%
Marketing and Trading	$287 11.8%	$58 28.2%	-$8 -5.4%	$414 4.5%
Other	$62 2.5%	-$32 -15.5%	-$32 -21.5%	$36 0.4%
Pinnacle West Capital Corp. (Consolidated)	$2,440	$206	$149	$9,139
		2003		
Regulated Electricity	$1,978 71.7%	$170 75.6%	$170 70.5%	$8,761 91.9%
Real Estate	$362 13.1%	$45 20.0%	$55 22.8%	$424 4.4%
Marketing and Trading	$391 14.2%	$8 3.6%	$9 3.7%	$324 3.4%
Other	$28 1.0%	$2 0.9%	$7 2.9%	$27 0.3%
Pinnacle West Capital Corp. (Consolidated)	$2,759	$225	$241	$9,536
		2004		
Regulated Electricity	$2,035 71.9%	$152 61.5%	$152 62.6%	$8,674 87.6%
Real Estate	$350 12.4%	$40 16.2%	$44 18.1%	$454 4.6%
Marketing and Trading	$401.0 14%	$29.0 12%	$17.0 7%	$746.0 8%
Other	$43 1.5%	$26 10.5%	$30 12.3%	$23 0.2%
Pinnacle West Capital Corp. (Consolidated)	$2,829	$247	$243	$9,897
		2005		
Regulated Electricity	$2,237 74.9%	$167 74.9%	$167 94.9%	$9,732 85.9%
Real Estate	$338 11.3%	$35 15.7%	$52 29.5%	$483 4.3%
Marketing and Trading	$352 11.8%	$16 7.2%	-$51 -29.0%	$1,070 9.4%
Other	$61 2.0%	$5 2.2%	$8 4.5%	$38 0.3%
Pinnacle West Capital Corp. (Consolidated)	$2,988	$223	$176	$11,323

Source: Pinnacle West Capital Corp., Form 10-K, various years, provided in response to Data

Exhibit___(DCP-1)
Schedule 4

BOND RATINGS

	Arizona Public Service		Pinnacle West Capital	
Date	Moody's	S&P	Moody's	S&P
2000	Baa2	BBB		
2001	Baa1	BBB	Baa2	BBB
2002	Baa1	BBB	Baa2	BBB-
2003	Baa1	BBB	Baa2	BBB-
2004	Baa1	BBB	Baa2	BBB-
2005	Baa1	BBB	Baa2	BB+
2006	Baa2	BBB-	Baa3 Provisional	BB+ Preliminary

Source: Response to Data Request TAI-3-4.

ARIZONA PUBLIC SERVICE COMPANY
CAPITAL STRUCTURE RATIOS
2001 - 2005
($Millions)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT 1/	SHORT-TERM DEBT
2001	$2,150.7	$0.0	$2,074.6	$171.2
	48.9%	0.0%	47.2%	3.9%
	50.9%	0.0%	49.1%	
2002	$2,159.3	$0.0	$2,220.8	$0.0
	49.3%	0.0%	50.7%	0.0%
	49.3%	0.0%	50.7%	
2003	$2,203.6	$0.0	$2,622.7	$0.0
	45.7%	0.0%	54.3%	0.0%
	45.7%	0.0%	54.3%	
2004	$2,232.4	$0.0	$2,718.3	$0.0
	45.1%	0.0%	54.9%	0.0%
	45.1%	0.0%	54.9%	
2005	$2,985.2	$0.0	$2,565.3	$0.0
	53.8%	0.0%	46.2%	0.0%
	53.8%	0.0%	46.2%	

1/ Includes current maturities.

Note: Percentages may not total 100.0% due to rounding.

Source: Response to Data Request TAI-3-20.

PINNACLE WEST CAPITAL CORP. (CONSOLIDATED)
CAPITAL STRUCTURE RATIOS
2001 - 2005
($millions)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT 1/	SHORT-TERM DEBT
2001	$2,499.3	$0.0	$2,799.2	$405.8
	43.8%	0.0%	49.1%	7.1%
	47.2%	0.0%	52.8%	
2002	$2,686.2	$0.0	$3,024.6	$227.7
	45.2%	0.0%	50.9%	3.8%
	47.0%	0.0%	53.0%	
2003	$2,829.8	$0.0	$3,321.5	$86.1
	45.4%	0.0%	53.3%	1.4%
	46.0%	0.0%	54.0%	
2004	$2,950.2	$0.0	$3,202.2	$71.0
	47.4%	0.0%	51.5%	1.1%
	48.0%	0.0%	52.0%	
2005	$3,425.0	$0.0	$2,993.4	$15.7
	53.2%	0.0%	46.5%	0.2%
	53.4%	0.0%	46.6%	

1/ Includes current maturities.

Note: Percentages may not total 100.0% due to rounding.

Source: Response to Data Request TAI-3-20.

Exhibit___(DCP-1)
Schedule 6

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2001	42%	38%
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

Exhibit___(DCP-1)
Schedule 7

COMPARISON COMPANIES
BASIS FOR SELECTION

Company	Market Cap (000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety	Moody's/ S&P Bond Rating	S&P Stock Ranking
Pinnacle West Capital	$4,000,000	74%	57%	1	BBB-/Baa1	A-
Comparison Group*						
Cleco Corp.	$1,100,000	95%	52%	3	BBB/Baa1	B+
DTE Energy	$7,500,000	55%	45%	3	BBB+/A3	B+
Energy East	$3,300,000	56%	44%	2	BBB+/A3	B+
Hawaiian Electric Industries	$2,200,000	82%	54%	2	NR/Baa2	B+
PNM Resources	$1,700,000	76%	42%	2	BBB/Baa2	B+
Puget Energy	$2,400,000	61%	46%	3	BBB/Baa2	B
Avera Proxy Group						
Black Hills Corp.	$1,200,000	22%	52%	3	BBB/Baa1	B
Edison International	$13,100,000	81%	41%	3	BBB+/A3	B
Hawaiian Electric	$2,200,000	82%	53%	2	NR/Baa2	B+
Idacorp	$1,500,000	98%	50%	3	A-/A3	B
MDU Resources Group	$4,400,000	5%	63%	1	A-/A2	A
PNM Resources Group	$1,700,000	76%	42%	2	BBB/Baa2	B+
Pinnacle West Capital	$4,000,000	74%	57%	1	BBB-/Baa1	A-
Puget Energy, Inc.	$2,400,000	61%	46%	3	BBB/Baa2	B
Sempra Energy	$12,000,000	45%	55%	2	A+/A1	B
Xcel Energy	$7,500,000	75%	47%	2	A-/A3	B

* Selected using following criteria:
Market cap of $1 billion to $8 billion.
Electric Revenues of 50% or greater.
Common Equity Ratio of 40% or greater.
Value Line Safety of 1, 2 or 3.
S&P and/or Moody's bond ratings of BBB.
S&P stock ranking of B, B, or A-..

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	May - July, 2006 HIGH	LOW	AVERAGE	YIELD
Comparison Group					
Cleco Corp.	$0.90	$25.09	$21.26	$23.18	3.9%
DTE Energy	$2.06	$43.63	$38.77	$41.20	5.0%
Energy East	$1.16	$24.75	$22.18	$23.47	4.9%
Hawaiian Electric Industries	$1.24	$28.74	$25.69	$27.22	4.6%
Pinnacle West Capital	$2.00	$44.20	$38.31	$41.26	4.8%
PNM Resources	$0.88	$27.84	$24.10	$25.97	3.4%
Puget Energy	$1.00	$22.45	$20.28	$21.37	4.7%
Average					**4.5%**
Avera Proxy Group					
Black Hills Corp.	$1.32	$37.52	$32.46	$34.99	3.8%
Edison International	$1.08	$42.40	$37.90	$40.15	2.7%
Hawaiian Electric	$1.24	$28.74	$25.69	$27.22	4.6%
Idacorp	$1.20	$37.47	$32.27	$34.87	3.4%
MDU Resources Group	$0.51	$37.25	$33.81	$35.53	1.4%
PNM Resources Group	$0.88	$27.84	$24.10	$25.97	3.4%
Pinnacle West Capital	$2.00	$44.20	$38.31	$41.26	4.8%
Puget Energy, Inc.	$1.00	$22.45	$20.28	$21.37	4.7%
Sempra Energy	$1.20	$48.64	$42.90	$45.77	2.6%
Xcel Energy	$0.89	$20.37	$18.10	$19.24	4.6%
Average					**3.6%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2001	2002	2003	2004	2005	Average	2006	2007	2009-2011	Average
Comparison Group										
Cleco Corp.	6.5%	5.6%	3.5%	3.9%	4.1%	4.7%	2.5%	3.0%	3.5%	3.0%
DTE Energy	0.1%	6.4%	2.5%	1.6%	3.7%	2.9%	0.0%	1.5%	4.5%	2.0%
Energy East	7.1%	2.9%	3.1%	3.8%	3.7%	4.1%	2.0%	2.0%	3.0%	2.3%
Hawaiian Electric Industries	4.4%	4.3%	3.9%	1.1%	1.5%	3.0%	1.5%	2.0%	3.0%	2.2%
Pinnacle West Capital	7.3%	2.9%	2.6%	2.3%	1.0%	3.2%	2.5%	3.5%	3.0%	3.0%
PNM Resources	12.3%	3.1%	3.0%	4.5%	4.3%	5.4%	4.0%	4.0%	3.5%	3.8%
Puget Energy	0.0%	1.3%	2.1%	2.8%	2.9%	1.8%	2.5%	3.0%	3.5%	3.0%
Average	5.4%	3.8%	3.0%	2.9%	3.0%	**3.6%**	2.1%	2.7%	3.4%	**2.8%**
Avera Proxy Group										
Black Hills Corp.	11.6%	6.0%	2.8%	2.3%	3.8%	5.3%	3.5%	4.0%	5.0%	4.2%
Edison International	13.6%	11.9%	13.6%	0.0%	12.3%	10.3%	9.0%	8.0%	6.0%	7.7%
Hawaiian Electric	4.4%	4.3%	3.9%	1.1%	1.5%	3.0%	1.5%	2.0%	3.0%	2.2%
Idacorp	6.3%	0.0%	0.0%	2.7%	1.3%	2.1%	2.5%	2.5%	3.0%	2.7%
MDU Resources Group	7.9%	5.0%	7.6%	7.9%	10.0%	7.7%	10.0%	9.0%	8.0%	9.0%
PNM Resources Group	12.3%	3.1%	3.0%	4.5%	4.3%	5.4%	4.0%	4.0%	3.5%	3.8%
Pinnacle West Capital	7.3%	2.9%	2.6%	2.3%	1.0%	3.2%	2.5%	3.5%	3.0%	3.0%
Puget Energy, Inc.	0.0%	1.3%	2.1%	2.8%	2.9%	1.8%	2.5%	3.0%	3.5%	3.0%
Sempra Energy	11.9%	13.1%	11.3%	14.9%	10.1%	12.3%	9.0%	8.5%	9.0%	8.8%
Xcel Energy	4.3%	0.0%	3.9%	3.9%	2.9%	3.0%	3.5%	3.5%	3.5%	3.5%
Average	8.0%	4.8%	5.1%	4.2%	5.0%	**5.4%**	4.8%	4.8%	4.8%	**4.8%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '03-'05 to '09-'11 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Comparison Group								
Cleco Corp.	1.0%	2.0%	4.0%	2.3%	4.5%	2.0%	8.0%	4.8%
DTE Energy	-2.0%	0.0%	3.5%	0.5%	4.5%	0.5%	2.0%	2.3%
Energy East	-2.5%	5.0%	6.0%	2.8%	4.0%	4.5%	2.5%	3.7%
Hawaiian Electric Industries	1.0%	0.0%	3.0%	1.3%	3.0%	0.0%	2.5%	1.8%
Pinnacle West Capital	-4.5%	6.5%	4.0%	2.0%	6.0%	5.0%	3.5%	4.8%
PNM Resources	-1.0%	5.0%	4.5%	2.8%	5.5%	8.5%	4.0%	6.0%
Puget Energy	-7.5%	-11.5%	0.5%	-6.2%	5.0%	1.5%	4.0%	3.5%
Average				**0.8%**				**3.9%**
Avera Proxy Group								
Black Hills Corp.		3.5%	16.0%	9.8%	6.5%	3.0%	4.0%	4.5%
Edison International		-9.0%	8.5%	-0.3%	7.0%		8.5%	7.8%
Hawaiian Electric	1.0%	0.0%	3.0%	1.3%	3.0%	0.0%	2.5%	1.8%
Idacorp	-11.0%	-6.0%	3.0%	-4.7%	4.5%	-2.0%	3.0%	1.8%
MDU Resources Group	12.5%	5.0%	12.5%	10.0%	8.0%	5.0%	10.5%	7.8%
PNM Resources Group	-1.0%	5.0%	4.5%	2.8%	5.5%	8.5%	4.0%	6.0%
Pinnacle West Capital	-4.5%	6.5%	4.0%	2.0%	6.0%	5.0%	3.5%	4.8%
Puget Energy, Inc.	-7.5%	-11.5%	0.5%	-6.2%	5.0%	1.5%	4.0%	3.5%
Sempra Energy	16.0%	-5.0%	10.5%	7.2%	5.5%	4.5%	11.0%	7.0%
Xcel Energy	-5.5%	-11.0%	-4.5%	-7.0%	6.0%	5.5%	3.0%	4.8%
Average				**1.5%**				**5.0%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group								
Cleco Corp.	4.0%	4.7%	3.0%	2.3%	4.8%	8.0%	4.6%	8.5%
DTE Energy	5.1%	2.9%	2.0%	0.5%	2.3%	4.5%	2.4%	7.5%
Energy East	5.0%	4.1%	2.3%	2.8%	3.7%	4.0%	3.4%	8.4%
Hawaiian Electric Industries	4.6%	3.0%	2.2%	1.3%	1.8%	3.0%	2.3%	6.9%
Pinnacle West Capital	4.9%	3.2%	3.0%	2.0%	4.8%	6.0%	3.8%	8.8%
PNM Resources	3.5%	5.4%	3.8%	2.8%	6.0%	8.5%	5.3%	8.8%
Puget Energy	4.8%	1.8%	3.0%		3.5%	4.0%	3.1%	7.8%
Average	4.5%	3.6%	2.8%	2.0%	3.9%	5.4%	3.6%	**8.1%**
Median								**8.4%**
Composite		8.2%	7.3%	6.5%	8.4%	**10.0%**	8.1%	
Avera Proxy Group								
Black Hills Corp.	3.9%	5.3%	4.2%	9.8%	4.5%	6.0%	5.9%	9.8%
Edison International	2.8%	10.3%	7.7%		7.8%	8.0%	8.4%	11.2%
Hawaiian Electric	4.6%	3.0%	2.2%	1.3%	1.8%	3.0%	2.3%	6.9%
Idacorp	3.5%	2.1%	2.7%		1.8%	5.0%	2.9%	6.4%
MDU Resources Group	1.5%	7.7%	9.0%	10.0%	7.8%	8.0%	8.5%	10.0%
PNM Resources Group	3.5%	5.4%	3.8%	2.8%	6.0%	8.5%	5.3%	8.8%
Pinnacle West Capital	4.9%	3.2%	3.0%	2.0%	4.8%	6.0%	3.8%	8.8%
Puget Energy, Inc.	4.8%	1.8%	3.0%		3.5%	4.0%	3.1%	7.8%
Sempra Energy	2.7%	12.3%	8.8%	7.2%	7.0%	5.3%	8.1%	10.8%
Xcel Energy	4.7%	3.0%	3.5%		4.8%	5.0%	4.1%	8.8%
Average	3.7%	5.4%	4.8%	5.5%	5.0%	5.9%	5.2%	**8.9%**
Median								**8.8%**
Composite		9.1%	8.5%	9.2%	8.7%	**9.6%**	8.9%	

Note: Negative average values not considered.

Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 9

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
Average			**14.02%**	**8.02%**	**6.00%**

Sources: Standard & Poor's Analysts' Handbook and Ibbotson Associates 2006 Yearbook.

COMPARISON COMPANIES
CAPM COST RATES
USING RISK PREMIUM

COMPANY	RISK-FREE RATE	BETA	MARKET PREMIUM	CAPM RATES
Comparison Group				
Cleco Corp.	5.30%	1.20	5.80%	12.3%
DTE Energy	5.30%	0.70	5.80%	9.4%
Energy East	5.30%	0.90	5.80%	10.5%
Hawaiian Electric Industries	5.30%	0.70	5.80%	9.4%
Pinnacle West Capital	5.30%	0.95	5.80%	10.8%
PNM Resources	5.30%	0.95	5.80%	10.8%
Puget Energy	5.30%	0.80	5.80%	9.9%
Average	5.30%	0.89	5.80%	**10.4%**
Median				**10.5%**
Avera Proxy Group				
Black Hills Corp.	5.30%	1.00	5.80%	11.1%
Edison International	5.30%	1.10	5.80%	11.7%
Hawaiian Electric	5.30%	0.70	5.80%	9.4%
Idacorp	5.30%	0.95	5.80%	10.8%
MDU Resources Group	5.30%	0.95	5.80%	10.8%
PNM Resources Group	5.30%	0.95	5.80%	10.8%
Pinnacle West Capital	5.30%	0.95	5.80%	10.8%
Puget Energy, Inc.	5.30%	0.80	5.80%	9.9%
Sempra Energy	5.30%	1.05	5.80%	11.4%
Xcel Energy	5.30%	0.85	5.80%	10.2%
Average	5.30%	0.93	5.80%	**10.7%**
Median				**10.8%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

Company	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average	2006	2007	2009-2011
Comparison Group																			
Cleco Corp.	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	13.4%	12.8%	8.5%	8.5%	9.0%
DTE Energy	16.7%	15.3%	11.8%	13.0%	11.8%	11.9%	12.2%	12.7%	11.9%	7.6%	13.7%	9.7%	8.1%	10.2%	12.7%	9.9%	5.5%	8.0%	10.5%
Energy East	10.7%	9.1%	10.3%	10.5%	10.1%	9.9%	11.2%	14.4%	15.1%	13.4%	9.3%	8.3%	9.1%	9.3%	11.5%	9.9%	8.5%	8.5%	9.5%
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	11.0%	10.9%	10.0%	10.0%	10.0%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.9%	11.5%	9.0%	8.5%	9.0%	9.0%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	10.0%	9.1%	8.5%	8.5%	8.5%
Puget Energy	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	10.4%	7.8%	8.0%	8.5%	8.5%
Average	11.7%	11.1%	11.0%	11.0%	11.1%	10.7%	11.7%	12.0%	12.5%	12.0%	10.2%	9.0%	9.0%	9.2%	11.5%	9.9%	8.2%	8.7%	9.3%
Composite															11.5%	9.9%			
Avera Proxy Group																			
Black Hills Corp.	16.2%	14.7%	13.9%	14.4%	16.1%	16.2%	16.8%	17.2%	21.5%	22.1%	12.1%	8.9%	7.9%	9.4%	16.9%	12.1%	9.5%	9.5%	10.0%
Edison International	13.4%	11.8%	11.5%	11.8%	11.2%	11.8%	12.7%	13.7%	-52.0%	14.9%	15.4%	15.8%	3.9%	17.4%	6.1%	13.5%	14.0%	13.0%	11.0%
Hawaiian Electric	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	11.0%	10.9%	10.0%	10.0%	10.0%
Idacorp	9.0%	11.2%	10.1%	11.5%	12.1%	12.4%	12.4%	12.3%	16.7%	14.9%	7.1%	4.2%	8.2%	7.3%	12.3%	8.3%	7.5%	7.0%	7.0%
MDU Resources Group	11.5%	12.2%	12.1%	12.4%	13.0%	14.3%	14.7%	13.7%	14.2%	15.0%	11.1%	13.4%	13.5%	15.4%	13.3%	13.7%	14.0%	13.0%	11.5%
PNM Resources Group	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	10.0%	9.1%	8.5%	8.5%	8.5%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.9%	11.5%	9.0%	8.5%	9.0%	9.0%
Puget Energy, Inc.	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	10.4%	7.8%	8.0%	8.5%	8.5%
Sempra Energy	14.3%	14.1%	13.6%	15.1%	14.9%	16.1%	9.5%	13.3%	16.5%	20.0%	20.7%	19.4%	20.7%	15.7%	14.7%	19.3%	13.5%	13.0%	12.5%
Xcel Energy	9.1%	11.3%	12.4%	13.5%	12.6%	10.3%	11.4%	8.8%	9.8%	13.2%	2.8%	10.0%	9.8%	9.1%	11.2%	9.0%	10.0%	9.5%	10.5%
Average	11.2%	11.6%	11.5%	11.9%	12.2%	12.1%	12.3%	12.3%	7.2%	14.9%	10.4%	10.5%	9.7%	10.8%	11.7%	11.3%	10.4%	10.1%	9.9%
Composite															11.7%	11.3%			

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

Company	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average
Comparison Group																
Cleco Corp.	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	177%	177%	181%	173%
DTE Energy	162%	154%	120%	130%	137%	126%	165%	145%	126%	142%	145%	142%	132%	140%	141%	140%
Energy East	131%	143%	105%	98%	94%	108%	169%	186%	151%	131%	121%	119%	138%	141%	131%	130%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	147%	162%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	136%	129%
PNM Resources	72%	84%	87%	95%	108%	106%	106%	85%	94%	123%	95%	93%	124%	147%	96%	116%
Puget Energy	149%	146%	112%	119%	130%	155%	170%	146%	143%	143%	126%	129%	137%	133%	141%	134%
Average	140%	140%	117%	124%	131%	138%	161%	144%	144%	152%	130%	126%	145%	150%	139%	141%
Composite															139%	141%
Avera Proxy Group																
Black Hills Corp.	264%	221%	169%	185%	198%	228%	255%	237%	301%	273%	143%	134%	134%	165%	233%	170%
Edison International	167%	172%	122%	116%	120%	158%	192%	173%	197%	128%	117%	108%	153%	205%	155%	142%
Hawaiian Electric	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	147%	162%
Idacorp	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	125%	122%	168%	136%
MDU Resources Group	155%	180%	169%	173%	179%	209%	245%	208%	201%	213%	155%	168%	185%	210%	193%	186%
PNM Resources Group	72%	84%	87%	95%	108%	106%	106%	85%	94%	123%	95%	93%	124%	147%	96%	116%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	136%	129%
Puget Energy, Inc.	149%	146%	112%	119%	130%	155%	170%	146%	143%	143%	126%	129%	137%	133%	141%	134%
Sempra Energy	187%	200%	166%	167%	171%	178%	203%	173%	165%	180%	155%	172%	178%	186%	179%	174%
Xcel Energy	164%	165%	154%	159%	162%	165%	176%	144%	141%	163%	113%	113%	132%	139%	159%	132%
Average	160%	162%	137%	143%	152%	168%	186%	160%	170%	171%	131%	129%	148%	162%	161%	148%
Composite															161%	148%

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 -2004

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
Averages:		
1992-2001	14.7%	341%
2000-2004	12.3%	334%

Source: Standard & Poor's Analyst's Handbook, 2005 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group	2.3	0.89	B++	B
Avera Proxy Group	2.2	0.93	B++	B+
Pinnacle West Capital	1.0	0.95	A	B

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COST OF CAPITAL

ITEM	PERCENT	COST RATE	WEIGHTED COST
Long-Term Debt	45.50%	5.41%	2.46%
Common Equity	54.50%	10.25%	5.59%
Total	100.00%		**8.05%**

Exhibit___(DCP-1)
Schedule 15

ARIZONA PUBLIC SERVICE COMPANY
PRE-TAX COVERAGE

ITEM	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST	
Long-Term Debt	45.50%	5.41%	2.46%	2.46%	
Common Equity	54.50%	10.25%	5.59%	9.41%	(1)
TOTAL CAPITAL	100.00%		8.05%	11.87%	

(1) Post-tax weighted cost divided by .59345 (composite tax factor)

Pre-tax coverage = 11.87%/2.46%
4.82 X

Standard & Poor's Utility Benchmark Ratios:

	A	BBB
Pre-tax coverage (X)		
Business Position:		
6	3.5 - 4.3x	2.4 - 3.5x
Total Debt to Total Capital (%)		
Business Position		
5	42 - 50%	50 - 60%

Note: Since 2004, S&P no longer uses the ratio "Pre-tax Coverage" as one of its benchmark ratios. The benchmark levels shown above reflect the 1999 levels cited by S&P.

EXHIBIT
S-9
admitted

BEFORE THE

ARIZONA CORPORATION COMMISSION

APPLICATION OF ARIZONA PUBLIC SERVICE CO. FOR AN INCREASE IN ELECTRIC RATES	))))	DOCKET NO. E-01345A-05-0816

SURREBUTTAL TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

COMMISSION STAFF

SEPTEMBER 27, 2006

BEFORE THE ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-05-0816

SURREBUTTAL TESTIMONY AND EXHIBIT

OF

DAVID C. PARCELL

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My Name is David C. Parcell. My address is Technical Associates, Inc., 1051 East Cary Street, Suite 601, Richmond, VA 23219.

Q. ARE YOU THE SAME DAVID C. PARCELL WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR CURRENT TESTIMONY?

A. My current testimony takes the form of surrebuttal testimony in response to the rebuttal testimony filed on September 15, 2006 by William E. Avera on behalf of Arizona Public Service Co. ("APS").

Q. HOW IS YOUR SURREBUTTAL TESTIMONY ORGANIZED?

A. My surrebuttal testimony is organized in a fashion to respond directly to Dr. Avera's rebuttal testimony. Accordingly, my surrebuttal testimony addresses the following topics:

- Reasonableness of Return
- DCF Analysis
- Risk Premium Approach
- Comparable Earnings Approach
- Flotation Costs
- Other Factors

REASONABLENESS OF RETURNS

Q. PLEASE SUMMARIZE DR. AVERA'S REBUTTAL TESTIMONY ON THE TOPIC OF "REASONABLENESS OF RETURNS."

A. In this section of his rebuttal testimony, Dr. Avera maintains that my recommendation, as well as the recommendation of RUCO witness Steven G. Hill, do not "meet the threshold test of reasonableness required by established regulatory and economic standards governing a fair rate of return on equity." Dr. Avera's apparent standard in this regard is that the fair return for a utility be "comparable to contemporaneous returns available from alternative investments of equivalent risk" so as to "maintain their financial flexibility and ability to attract capital."

Q. HOW DOES DR. AVERA ASSESS THE CONTEMPORANEOUS RETURNS STANDARD HE CITES?

A. Dr. Avera appears to place a lot of emphasis on the returns authorized for other utilities. On page 8, he cites average authorized returns on equity of 10.69 percent and 10.57 percent in 2006. It is noteworthy that such returns do not nearly justify the 11.5 percent return on equity he appears to be recommending for APS in this proceeding. I say appears since it seems that Dr. Avera is now recommending, for the first time, an attrition allowance of 1.7 percent for APS that was not part of his direct testimony. I do not regard an "attrition adjustment" to be a cost of capital issue. I do, however, disagree with the inclusion of such a significant, new issue at this stage of the proceeding under any guise. It is my understanding that ACC Staff Witness Dittmer is sponsoring testimony that addresses the proposed attrition adjustment, and I would recommend denying any adjustment to the cost of capital that is based on "attrition" rather than cost of capital analysis.

Dr. Avera's Attachment WEA-1RB shows what he represents are authorized returns on equity for my proxy group and Mr. Hill's proxy group. I note that his source is AUS Utility Reports, which often does not cite the date of the authorized returns meaning that some of these authorized returns could be several years old. It is noteworthy that Dr.

Avera's Attachment WEA-1RB does not list an "Allowed ROE" for Pinnacle West, notwithstanding the fact that his source document (AUS Utility Reports) lists a 10.25 percent return on equity for this company.

I also note that I am personally familiar with one of these authorized returns he cites. Hawaiian Electric had a rate proceeding in 2005 in which there was a stipulated return on equity of 10.7 percent (not the 10.82 percent cited by Dr. Avera). It is also noteworthy that the capital structure to which this return on equity was applied was about 46 percent, or well below that requested by APS (54.5 percent) in this proceeding. This demonstrates that a mere listing of authorized returns on equity can be misleading and, in the case of Hawaiian Electric, is misleading in the context of APS.

Q. DO YOU HAVE ANY PERSONAL EXPERIENCE WITH AUTHORIZED RETURNS OF EQUITY FOR PUBLIC UTILITIES IN CASES THAT HAVE BEEN DECIDED IN 2006?

A. Yes, I do. I have been personally involved in the following three proceedings which were both heard and decided in 2006:

Company	State	Docket	ROE
Delmarva P&L	Delaware	05-304	10.0%
Virginia Natural Gas	Virginia	2005-00062	10.0%
Sierra Pacific Power	Nevada	05-100005	10.6%

It is noteworthy that none of these authorized return even remotely approached the 11.5 percent (or greater) recommended by Dr. Avera in this proceeding.

Q. DO YOU HAVE ANY CONCLUDING REMARKS ABOUT DR AVERA'S REFERENCE TO AUTHORIZED RETURNS ON EQUITY?

A. Yes, I do. Dr. Avera attempts to use authorized returns on public utilities to criticize my recommended return on equity. In reality, authorized returns are much closer to my

recommended return on equity (10.25 percent) than to his recommended return on equity (11.50 percent plus 1.7 percent attrition).

Q. DR. AVERA STATES, ON PAGE 9, THAT VALUE LINE PROJECTS ELECTRIC UTILITIES TO EARN 11.5 PERCENT FROM 2007 TO 2011. DOES THIS INDICATE THAT 11.5 PERCENT IS THE COST OF EQUITY FOR ELECTRIC UTILITIES?

A. No, it does not. I noted in my direct testimony that electric utilities, as represented by my proxy group and Dr. Avera's proxy group, have had market-to-book ratios that significantly exceed 100 percent. This is significant since investors are aware that electric utilities are regulated based on the book value of their assets and the book value of their equity. The only rational reason for pricing a utility's stock significantly above book value is an expectation that the utility will earn a return above its cost of capital. This relationship is not recognized in Dr. Avera's rebuttal testimony. I also note that the projected returns on equity for Dr. Avera's proxy group for the 2009-2011 period is 9.9 percent, as estimated by Value Line and shown on my Schedule 11.

Q. DR. AVERA CITES, ON PAGE 10, THE REGULATORY ENVIRONMENT OF ARIZONA AS A FACTOR THAT HE PERCEIVES SHOULD IMPACT THE AUTHORIZED RETURN ON EQUITY IN THIS PROCEEDING. DO YOU HAVE ANY COMMENTS ON THIS ASSERTION?

A. Yes, I do. I have also cited this State's regulatory environment in my direct testimony. I also noted that the Staff in this proceeding is recommending an enhanced methodology for recovery of fuel and purchased power costs in this proceeding. Dr. Avera does not acknowledge this in his rebuttal testimony.

In any event, there in no need to authorize a return on equity for APS that exceeds its fair cost of equity. Yet, this is essentially what Dr. Avera is implicitly recommending.

Q. DO YOU HAVE ANY OTHER GENERAL COMMENTS ABOUT DR. AVERA'S PERCEPTION OF THE ALTERNATIVE RETURNS IN THE ECONOMY?

A. Yes, I do. It is apparent that the returns expected by investors are lower now than has been the case throughout the past three decades. This is, of course, not surprising since interest rates and inflation are both low by historic standards. The table below cites the returns for several major stock indices for periods ending June 30, 2006:

Index	Year-to-date	1 Year	5 Years	10 Years
S&P 500	2.71%	8.63%	2.49%	8.32%
Wilshire 4500	5.51%	13.87%	9.03%	9.32%
Russell 2000	8.21%	14.58%	8.50%	9.05%

(Source: Vanguard)

It is evident that returns to investors in the largely unregulated sector of the U. S. economy are much less than the 11.5 percent recommendation of Dr. Avera and, in fact, are generally lower than my recommended 10.25 percent return on equity for APS.

DCF ANALYSIS

Q. ON PAGE 12 OF HIS REBUTTAL TESTIMONY, DR. AVERA TAKES ISSUE WITH YOUR PROXY GROUP OF ELECTRIC UTILITIES. DO YOU HAVE ANY RESPONSE TO HIS ASSERTION?

A. Yes, I do. I note, first of all, my proxy group is designed to select a group of companies as closely related to APS and PWC as possible. My Schedule 7 indicates that my proxy group is more closely related to APS and PWC than is Dr. Avera's proxy group.

I also note that my cost of equity analyses are also applied to Dr. Avera's proxy group, indicating that I have used both groups in my analyses and conclusions. I observe that Dr. Avera does not acknowledge this in his rebuttal testimony. This is further noteworthy since my DCF results are higher for my proxy group than for Dr. Avera's proxy group, meaning that I likely would have obtained a lower DCF conclusion had I not used my own proxy group. Dr. Avera also does not acknowledge this in his rebuttal testimony.

Q. DR. AVERA MAINTAINS, ON PAGE 14, LINE 11, THAT YOU HAVE PLACED "RELIANCE ON HISTORICAL GROWTH RATES." IS HE CORRECT?

A. No, he is not. As is apparent from my direct testimony, my DCF conclusion is a range of 9 percent to 10 percent (Page 24, Lines 9-12). It is also apparent from my Schedule 8, Page 4, that my recommended DCF range is essentially determined by reference to prospective growth rates, as the historic growth rates produce DCF costs below the 9 percent lower end.

Q. DR. AVERA FURTHER MAINTAINS, ON PAGES 14 TO 15, THAT YOU HAVE A "DOWNWARD BIAS OF HISTORICAL GROWTH MEASURES." IS HE CORRECT?

A. No, he is not correct. As I indicated in the prior response, the historic growth rates did not factor into my 9 percent to 10 percent DCF conclusion.

Q. DR. AVERA CRITICIZES YOUR RETENTION GROWTH RATE (PAGES 15-17). IS THIS CRITICISM JUSTIFIED?

A. No, it is not. My retention growth uses the measurement of this statistic as reported by Value Line Investment Survey. The ratio that I employed in my analyses thus matches the one likely used by investors who read and use Value Line for investment decisions.

Q. ON PAGES 17-18, DR. AVERA ALSO CRITICIZES YOU FOR NOT INCLUDING THE IMPACT OF NEW STOCK ISSUANCES IN YOUR RETENTION GROWTH RATES. IS THIS A VALID CRITICISM?

A. No, it is not. There is very little impact on retention growth associated with new stock issuances. As evidence of this, I have calculated the "s x v" component Dr. Avera refers to, using the Federal Energy Regulatory Commission methodology. The following growth rates apply to the companies in my proxy group:

Cleco	0.94%
DTE Energy	-0.46%
Energy East	0.05%
HEI	0.12%
PWC	0.00%
PNM Res	0.36%
Puget Energy	0.20%
Average	0.17%

This demonstrates that only 0.17 percent would be added to the retention growth rates if the impact of stock issuances is added. If this were added to my prospective retention growth in my Schedule 8, Page 4, the DCF results would still be below 9 percent, the lower bound of my recommendation.

Q. DR. AVERA ALSO APPEARS TO BE PROPOSING USE OF A MULTI-STAGE DCF ON PAGES 20-21. DO YOU HAVE ANY COMMENTS ON THIS?

A. Yes, I do. If Dr. Avera believed that a multi-stage DCF model was proper, he should have included this in his own DCF analyses. The fact that he did not indicates that he has not favored such a DCF model.

Q. DO YOU HAVE ANY OTHER COMMENTS ABOUT DR. AVERA'S REBUTTAL TO YOUR DCF ANALYSES?

A. Yes, I do. I find it interesting that Dr. Avera criticizes my DCF results, which are 9 percent to 10 percent, while his own DCF results are 9 percent. It is apparent that my conclusions exceed his DCF conclusions.

RISK PREMIUM (CAPM) APPROACH

Q. ON PAGE 22, DR AVERA CRITICIZES YOUR EQUITY RISK PREMIUM COMPONENT OF THE CAPM BY SAYING YOUR ANALYSES DO NOT INCORPORATE INVESTOR EXPECTATIONS. IS THIS A FAIR CRITICISM?

A. No, it is not. I note that Dr. Avera cites his Attachment WEA-6 from his direct testimony as a source of forward-looking returns. A review of this document indicates that Dr. Avera's "forward looking" market returns are represented by a DCF analysis of dividend paying firms in the S&P 500. I also used the S&P 500 as the source of expected returns in my risk premium. My three sources of expected returns for the S&P 500 are:

14.02% -- 1978-2004 achieved returns on equity
12.3% -- 1926-2005 arithmetic holding period returns
10.4% -- 1926-2005 geometric holding period returns

These three sets of returns exceed the more recent returns of the S&P 500, which were cited earlier:

2.71% -- year-to-date
8.63% -- one year
2.49% -- 5 years
8.32% -- 10 years

Dr. Avera apparently believes that investors expect to achieve a return of 13.5 percent, notwithstanding the fact that such returns have not and are not being earned by the S&P 500.

Q. DR. AVERA MAINTAINS, ON PAGES 23-25, THAT YOU SHOULD NOT HAVE CONSIDERED GEOMETRIC RETURNS IN YOUR RISK PREMIUM ANALYSES. WHAT ARE YOUR COMMENTS ON THIS?

A. What is important is not what Dr. Avera and I believe, but what investors rely upon in making investment decisions. It is apparent that investors have access to both types of returns when they make investment decisions.

In fact, it is noteworthy that mutual fund investors regularly receive reports on their own funds, as well as prospective funds they are considering investing in, that show only geometric returns. Based on this, I find it difficult to accept Dr. Avera's position that only arithmetic returns are appropriate.

Q. DOES DR. AVERA USE VALUE LINE INFORMATION IN HIS COST OF CAPITAL ANALYSES?

A. Yes, he does.

Q. DO VALUE LINE REPORTS SHOW HISTORIC GROWTH RATES FOR UTILITIES?

A. Yes, they do.

Q. DO THESE VALUE LINE REPORTS SHOW HISTORIC RETURNS ON AN ARITHMETIC BASIS?

A. No, they do not.

Q. DO THE VALUE LINE REPORTS SHOW HISTORIC RETURNS ON A GEOMETRIC, OR COMPOUND GROWTH RATE BASIS?

A. Yes, they do. As a result, any investor reviewing Value Line, as Dr. Avera does, would be using geometric growth rates.

Q. IS IT YOUR POSITION THAT ONLY GEOMETRIC GROWTH RATES BE USED?

A. No. I believe that both arithmetic and geometric growth rates should be used. This is the case since investors have access to both and presumably use both.

Q. BUT DOES NOT DR. AVERA CITE HIS PERCEPTION THAT "FINANCIAL LITERATURE" REQUIRES THAT ARITHMETIC RETURNS BE USED EXCLUSIVELY?

A. He does state this in his testimony. However, the cost of capital determination is not an academic exercise made in some laboratory or university classroom. The true cost of equity is made in the "laboratory" of the financial markets, based on the ongoing inter-play of countless investors, each with their own agendas and beliefs. This is verified by the fact that each time a share of stock is purchased by one investor, it is simultaneously being sold by another investor, indicating that their respective views at that time differ.

Again, investors have access to both arithmetic and geometric growth rates. In all likelihood, there is more geometric growth readily available to investors (e.g., mutual fund reports and Value Line) than arithmetic growth.

Q. DR. AVERA ALSO MAINTAINS, ON PAGES 25-27, THAT ONLY THE INCOME COMPONENT OF BOND RETURNS SHOULD BE USED TO DETERMINE THE RISK PREMIUM. DO YOU AGREE WITH THIS?

A. No, I do not. Dr. Avera is proposing to compute an equity risk premium which uses one measure of returns (i.e., total returns-dividends plus capital gains) for stocks and a different measure of return (i.e., income returns, which ignores capital gains) for bonds. He is thus inconsistent in his selection of returns in a manner that overstates the risk premium and thus CAPM result.

COMPARABLE EARNINGS APPROACH

Q. ON PAGES 27-28, DR AVERA CLAIMS YOUR COMPARABLE EARNINGS APPROACH IS NOT "INTERNALLY CONSISTENT." IS HE CORRECT?

A. No, he is not. First, when Dr. Avera cites that the S&P 500 has earned about 13.5 percent in recent years, this does not mean that investors expect these returns to be earned in the future and it also does not mean that this figure represents the cost of capital to the S&P 500. As I indicated in my testimony (Page 30), the S&P 500 has had market-to-book ratios of over 300 percent (i.e., price is over three times book), which strongly suggests that returns of 13.5 percent exceed the cost of capital.

Second, electric utilities are less risky than the S&P 500 and do not require the same level of returns. My direct testimony (Page 30) also shows that the projected returns on equity for both my proxy group and Dr. Avera's proxy group are 10.4 percent or less. Yet these companies had 2005 market-to-book ratios of over 150 percent, indicating that investors accept these expected returns as being more than adequate.

FLOTATION COSTS

Q. DR. AVERA CRITICIZES YOUR POSITION ON FLOTATION COSTS (PAGES 29-30) BY STATING THAT IT IS INCONSISTENT WITH YOUR OWN RESEARCH ON THIS SUBJECT. DO YOU HAVE ANY COMMENTS ON THIS?

A. Yes, I do. Dr. Avera is being very selective in his description of my "research." In his testimony, he is citing a paper I prepared in 1993 on the ways to measure flotation costs,

as well as the use of flotation cost adjustments by commissions. What Dr. Avera did not cite was my "research" finding that the majority of commissions have not made flotation cost adjustments.

Q. IS A FLOTATION COST ADJUSTMENT NECESSARY FOR APS?

A. No, it is not. APS already has a relatively high common equity ratio. In addition, Dr. Avera has made no demonstration that APS has recently incurred any flotation costs. Further, should PWC issue common stock, it would be at a price above book value, meaning that existing shareholders would enjoy an accretion to the value of their existing book value. Finally, I note that Value Line estimates no increase in the shares outstanding of PWC between now and 2009-2011.

OTHER ISSUES

Q. DR. AVERA MAKES SEVERAL REFERENCES TO A PRIOR TESTIMONY OF ACC STAFF WITNESS DENNIS ROGERS AND IMPLIES THAT YOUR TESTIMONY AND MR. ROGERS' TESTIMONIES ARE IN CONFLICT. DO YOU HAVE ANY RESPONSE TO THIS?

A. Yes, I do. The testimony that Dr. Avera cites was filed by Mr. Rogers on January 16, 2005 in Docket No. W-01303A-05-0405. I note, first of all, that I was retained by the ACC Staff in the current proceeding to provide my own analyses and conclusions, not to duplicate the analyses or results of any other witness, including Staff witnesses. Having said this, my review of Mr. Rogers testimony reveals to me that our conclusions are very similar. In his testimony, Mr. Rogers recommended, for Paradise Valley Water Company, a subsidiary of American Water, a return on equity range of 9.6 percent (DCF results) to 10.0 percent (CAPM results) plus a 0.6 percent "upward financial risk adjustment" which was designed to recognize the financial risk associated with the 36.7 percent common equity ratio of the utility. In the case of Paradise Valley Water, the subject utility had more leverage and thus financial risk than the proxy group. In the case of APS, on the other hand, the opposite situation occurs, since APS has a higher equity ratio and thus less financial risk than the proxy group.

What Dr. Avera has obviously done is cite certain portions of Mr. Rogers' testimony and attempt to create a perceived conflict between my testimony and that of Mr. Rogers. Dr. Avera does not acknowledge that my 10.25 percent recommendation for APS and Mr. Rogers' 10.4 percent recommendation (9.8 percent prior to financial risk adjustment) are quite compatible. Clearly, Dr. Avera has taken Mr. Rogers' testimony out of context and, in the process, has ignored the most important aspect of mine and Mr. Rogers' testimonies – our "bottom line" recommendations.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes it does.

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

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 TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816 **NOTICE OF FILING**
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827

Consistent with the eleventh ordering paragraph of the April 5, 2006 procedural order, Arizona Corporation Commission Staff ("Staff") hereby provides notice of filing updates to the schedules to the Direct Testimony of Staff witness David C. Parcell. The following schedules have been updated: Schedules 2, 8, 9, 10, page 1 of 11, and 13. Also included is his summary of this updated information.

RESPECTFULLY SUBMITTED this 2nd day of November, 2006.

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ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
		1975 - 1982 Cycle			
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
		1983 - 1991 Cycle			
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
		1992 - 2001 Cycle			
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.2%	5.4%	3.3%	2.8%
1997	4.5%	7.3%	4.9%	1.7%	-1.2%
1998	4.2%	5.9%	4.5%	1.6%	0.0%
1999	4.5%	4.5%	4.2%	2.7%	2.9%
2000	3.7%	4.3%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
		Current Cycle			
2002	1.6%	0.1%	5.8%	2.4%	1.2%
2003	2.7%	0.6%	6.0%	1.9%	4.0%
2004	4.2%	4.1%	5.5%	3.3%	4.2%
2005	3.5%	3.3%	5.1%	3.4%	5.4%
2004					
1st Qtr.	4.3%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	4.0%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	3.3%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.8%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.2%	1.6%
3rd Qtr.	4.1%	2.7%	5.0%	9.6%	10.8%
4th Qtr.	1.7%	3.1%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.9%	4.6%	4.6%	4.8%	5.6%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.40%
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	5.42%
4th Qtr.	1,230.47	2,178.67	10,615.78	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	Aug. - Oct. 2006 HIGH	LOW	AVERAGE	YIELD
Comparison Group					
Cleco Corp.	$0.90	$26.20	$24.00	$25.10	3.6%
DTE Energy	$2.06	$45.97	$40.26	$43.12	4.8%
Energy East	$1.20	$25.20	$23.37	$24.29	4.9%
Hawaiian Electric Industries	$1.24	$28.94	$26.07	$27.51	4.5%
Pinnacle West Capital	$2.10	$48.93	$42.91	$45.92	4.6%
PNM Resources	$0.88	$29.08	$26.37	$27.73	3.2%
Puget Energy	$1.00	$24.17	$21.97	$23.07	4.3%
Average					**4.3%**
Avera Proxy Group					
Black Hills Corp.	$1.32	$36.86	$33.26	$35.06	3.8%
Edison International	$1.08	$44.94	$40.70	$42.82	2.5%
Hawaiian Electric	$1.24	$28.94	$26.07	$27.51	4.5%
Idacorp	$1.20	$40.17	$36.04	$38.11	3.1%
MDU Resources Group	$0.54	$26.24	$22.25	$24.25	2.2%
PNM Resources Group	$0.88	$29.08	$26.37	$27.73	3.2%
Pinnacle West Capital	$2.10	$48.93	$42.91	$45.92	4.6%
Puget Energy, Inc.	$1.00	$24.17	$21.97	$23.07	4.3%
Sempra Energy	$1.20	$53.85	$46.56	$50.21	2.4%
Xcel Energy	$0.89	$22.15	$19.90	$21.03	4.2%
Average					**3.5%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2001	2002	2003	2004	2005	Average	2006	2007	2009-2011	Average
Comparison Group										
Cleco Corp.	6.5%	5.6%	3.5%	3.9%	4.1%	4.7%	2.5%	3.0%	4.0%	3.2%
DTE Energy	0.1%	6.4%	2.5%	1.6%	3.7%	2.9%	0.0%	1.0%	4.0%	1.7%
Energy East	7.1%	2.9%	3.1%	3.8%	3.7%	4.1%	2.5%	2.0%	2.5%	2.3%
Hawaiian Electric Industries	4.4%	4.3%	3.9%	1.1%	1.5%	3.0%	1.5%	2.0%	3.5%	2.3%
Pinnacle West Capital	7.3%	2.9%	2.6%	2.3%	1.0%	3.2%	2.5%	3.5%	3.0%	3.0%
PNM Resources	12.3%	3.1%	3.0%	4.5%	4.3%	5.4%	4.0%	4.0%	3.5%	3.8%
Puget Energy	0.0%	1.3%	2.1%	2.8%	2.9%	1.8%	2.0%	3.0%	3.5%	2.8%
Average	5.4%	3.8%	3.0%	2.9%	3.0%	**3.6%**	2.1%	2.6%	3.4%	**2.7%**
Avera Proxy Group										
Black Hills Corp.	11.6%	6.0%	2.8%	2.3%	3.8%	5.3%	3.5%	4.5%	5.0%	4.3%
Edison International	13.6%	11.9%	13.6%	0.0%	12.3%	10.3%	9.5%	9.0%	6.5%	8.3%
Hawaiian Electric	4.4%	4.3%	3.9%	1.1%	1.5%	3.0%	1.5%	2.0%	3.5%	2.3%
Idacorp	6.3%	0.0%	0.0%	2.7%	1.3%	2.1%	2.5%	2.5%	3.0%	2.7%
MDU Resources Group	7.9%	5.0%	7.6%	7.9%	10.0%	7.7%	10.0%	9.0%	7.5%	8.8%
PNM Resources Group	12.3%	3.1%	3.0%	4.5%	4.3%	5.4%	4.0%	4.0%	3.5%	3.8%
Pinnacle West Capital	7.3%	2.9%	2.6%	2.3%	1.0%	3.2%	2.5%	3.5%	3.0%	3.0%
Puget Energy, Inc.	0.0%	1.3%	2.1%	2.8%	2.9%	1.8%	2.0%	3.0%	3.5%	2.8%
Sempra Energy	11.9%	13.1%	11.3%	14.9%	10.1%	12.3%	8.0%	8.0%	8.5%	8.2%
Xcel Energy	4.3%	0.0%	3.9%	3.9%	2.9%	3.0%	4.0%	3.5%	3.5%	3.7%
Average	8.0%	4.8%	5.1%	4.2%	5.0%	**5.4%**	4.8%	4.9%	4.8%	**4.8%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '03-'05 to '09-'11 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Comparison Group								
Cleco Corp.	1.0%	2.0%	4.0%	2.3%	4.5%	2.0%	8.5%	5.0%
DTE Energy	-2.0%	0.0%	3.5%	0.5%	3.0%	0.5%	1.5%	1.7%
Energy East	-2.5%	5.0%	6.0%	2.8%	4.0%	4.5%	2.5%	3.7%
Hawaiian Electric Industries	1.0%	0.0%	3.0%	1.3%	3.0%	0.0%	2.5%	1.8%
Pinnacle West Capital	-4.5%	6.5%	4.0%	2.0%	6.0%	5.0%	3.5%	4.8%
PNM Resources	-1.0%	5.0%	4.5%	2.8%	5.5%	8.5%	4.0%	6.0%
Puget Energy	-7.5%	-11.5%	0.5%	-6.2%	5.0%	1.5%	4.0%	3.5%
Average				**0.8%**				**3.8%**
Avera Proxy Group								
Black Hills Corp.		3.5%	16.0%	9.8%	6.5%	3.0%	4.0%	4.5%
Edison International		-9.0%	8.5%	-0.3%	8.0%		9.0%	8.5%
Hawaiian Electric	1.0%	0.0%	3.0%	1.3%	3.0%	0.0%	2.5%	1.8%
Idacorp	-11.0%	-6.0%	3.0%	-4.7%	4.5%	-2.0%	3.0%	1.8%
MDU Resources Group	12.5%	5.0%	12.5%	10.0%	8.0%	7.0%	10.5%	8.5%
PNM Resources Group	-1.0%	5.0%	4.5%	2.8%	5.5%	8.5%	4.0%	6.0%
Pinnacle West Capital	-4.5%	6.5%	4.0%	2.0%	6.0%	5.0%	3.5%	4.8%
Puget Energy, Inc.	-7.5%	-11.5%	0.5%	-6.2%	5.0%	1.5%	4.0%	3.5%
Sempra Energy	16.0%	-5.0%	10.5%	7.2%	5.5%	4.5%	12.0%	7.3%
Xcel Energy	-5.5%	-11.0%	-4.5%	-7.0%	6.0%	5.5%	3.5%	5.0%
Average				**1.5%**				**5.2%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group								
Cleco Corp.	3.7%	4.7%	3.2%	2.3%	5.0%	8.0%	4.6%	8.3%
DTE Energy	4.8%	2.9%	1.7%	0.5%	1.7%	4.5%	2.2%	7.1%
Energy East	5.0%	4.1%	2.3%	2.8%	3.7%	4.0%	3.4%	8.4%
Hawaiian Electric Industries	4.6%	3.0%	2.3%	1.3%	1.8%	3.0%	2.3%	6.9%
Pinnacle West Capital	4.7%	3.2%	3.0%	2.0%	4.8%	6.0%	3.8%	8.5%
PNM Resources	3.3%	5.4%	3.8%	2.8%	6.0%	12.0%	6.0%	9.3%
Puget Energy	4.4%	1.8%	2.8%		3.5%	4.0%	3.0%	7.4%
Average	4.3%	3.6%	2.7%	2.0%	3.8%	5.9%	3.6%	**8.0%**
Median								**8.3%**
Composite		7.9%	7.1%	6.3%	8.1%	**10.3%**	8.0%	
Avera Proxy Group								
Black Hills Corp.	3.9%	5.3%	4.3%	9.8%	4.5%	4.5%	5.7%	9.5%
Edison International	2.6%	10.3%	8.3%		8.5%	9.0%	9.0%	11.7%
Hawaiian Electric	4.6%	3.0%	2.3%	1.3%	1.8%	3.0%	2.3%	6.9%
Idacorp	3.2%	2.1%	2.7%		1.8%	5.0%	2.9%	6.1%
MDU Resources Group	2.3%	7.7%	8.8%	10.0%	8.5%	6.5%	8.3%	10.6%
PNM Resources Group	3.3%	5.4%	3.8%	2.8%	6.0%	12.0%	6.0%	9.3%
Pinnacle West Capital	4.7%	3.2%	3.0%	2.0%	4.8%	6.0%	3.8%	8.5%
Puget Energy, Inc.	4.4%	1.8%	2.8%		3.5%	4.0%	3.0%	7.4%
Sempra Energy	2.5%	12.3%	8.2%	7.2%	7.3%	4.6%	7.9%	10.4%
Xcel Energy	4.3%	3.0%	3.7%		5.0%	5.0%	4.2%	8.5%
Average	3.6%	5.4%	4.8%	5.5%	5.2%	6.0%	5.3%	**8.9%**
Median								**8.9%**
Composite		9.0%	8.4%	9.1%	8.8%	**9.5%**	8.9%	

Note: Negative average values not considered.

Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 9
Updated

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
Average			**14.02%**	**7.90%**	**6.19%**

Sources: Standard & Poor's Analysts' Handbook and Ibbotson Associates 2006 Yearbook.

COMPARISON COMPANIES
CAPM COST RATES
USING RISK PREMIUM

COMPANY	RISK-FREE RATE	BETA	MARKET PREMIUM	CAPM RATES
Comparison Group				
Cleco Corp.	4.99%	1.25	5.90%	12.4%
DTE Energy	4.99%	0.75	5.90%	9.4%
Energy East	4.99%	0.90	5.90%	10.3%
Hawaiian Electric Industries	4.99%	0.70	5.90%	9.1%
Pinnacle West Capital	4.99%	1.00	5.90%	10.9%
PNM Resources	4.99%	1.00	5.90%	10.9%
Puget Energy	4.99%	0.80	5.90%	9.7%
Average	4.99%	0.91	5.90%	**10.4%**
Median				**10.3%**
Avera Proxy Group				
Black Hills Corp.	4.99%	1.10	5.90%	11.5%
Edison International	4.99%	1.10	5.90%	11.5%
Hawaiian Electric	4.99%	0.70	5.90%	9.1%
Idacorp	4.99%	1.00	5.90%	10.9%
MDU Resources Group	4.99%	1.00	5.90%	10.9%
PNM Resources Group	4.99%	1.00	5.90%	10.9%
Pinnacle West Capital	4.99%	1.00	5.90%	10.9%
Puget Energy, Inc.	4.99%	0.80	5.90%	9.7%
Sempra Energy	4.99%	1.05	5.90%	11.2%
Xcel Energy	4.99%	0.90	5.90%	10.3%
Average	4.99%	0.97	5.90%	**10.7%**
Median				**10.9%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

Company	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average	2006	2007	2009-2011
Comparison Group																			
Cleco Corp.	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	13.4%	12.8%	8.5%	8.5%	9.5%
DTE Energy	18.7%	15.3%	11.8%	13.0%	11.8%	11.9%	12.2%	12.7%	11.9%	7.6%	13.7%	9.7%	8.1%	10.2%	12.7%	9.9%	6.5%	7.5%	10.0%
Energy East	10.7%	9.1%	10.3%	10.5%	10.1%	9.9%	11.2%	14.4%	15.1%	13.4%	9.3%	8.3%	9.1%	9.3%	11.5%	9.9%	8.5%	8.0%	9.0%
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	11.0%	10.9%	10.0%	10.0%	11.0%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.9%	11.5%	9.0%	8.5%	9.0%	9.0%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	10.0%	9.1%	8.5%	8.5%	8.5%
Puget Energy	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	10.4%	7.8%	7.5%	8.5%	8.5%
Average	11.7%	11.1%	11.0%	11.0%	11.1%	10.7%	11.7%	12.0%	12.5%	12.0%	10.2%	9.0%	9.0%	9.2%	11.5%	9.9%	8.3%	8.8%	9.4%
Composite															11.5%	9.9%			
Avera Proxy Group																			
Black Hills Corp.	16.2%	14.7%	13.9%	14.4%	16.1%	16.2%	16.8%	17.2%	21.5%	22.1%	12.1%	8.9%	7.9%	9.4%	16.9%	12.1%	9.5%	10.0%	10.5%
Edison International	13.4%	11.8%	11.5%	11.8%	11.2%	11.8%	12.7%	13.7%	-52.0%	14.9%	15.4%	15.8%	3.9%	17.4%	6.1%	13.5%	14.5%	13.5%	11.0%
Hawaiian Electric	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	11.0%	10.9%	10.0%	10.0%	11.0%
Idacorp	9.0%	11.2%	10.1%	11.8%	12.1%	12.4%	12.4%	12.3%	16.7%	14.9%	7.1%	4.2%	8.2%	7.3%	12.3%	8.3%	7.5%	7.0%	7.0%
MDU Resources Group	11.5%	12.2%	12.1%	12.4%	13.0%	14.3%	14.7%	13.7%	14.2%	15.0%	11.1%	13.4%	13.5%	15.4%	13.3%	13.7%	14.0%	13.0%	11.5%
PNM Resources Group	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	10.0%	9.1%	8.5%	8.5%	8.5%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.9%	11.5%	9.0%	8.5%	9.0%	9.0%
Puget Energy, Inc.	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	10.4%	7.8%	7.5%	8.5%	8.5%
Sempra Energy	14.3%	14.1%	13.6%	15.1%	14.9%	16.1%	9.5%	13.3%	16.5%	20.0%	20.7%	19.4%	20.7%	15.7%	14.7%	19.3%	12.5%	12.0%	12.0%
Xcel Energy	9.1%	11.3%	12.4%	13.5%	12.6%	10.3%	11.4%	8.8%	9.8%	13.2%	2.8%	10.0%	9.8%	9.1%	11.2%	9.0%	10.0%	9.5%	10.5%
Average	11.2%	11.6%	11.5%	11.9%	12.2%	12.1%	12.3%	12.3%	7.2%	14.9%	10.4%	10.5%	9.7%	10.8%	11.7%	11.3%	10.3%	10.1%	10.0%
Composite															11.7%	11.3%			

Source: Calculations made from data contained in Value Line Investment Survey.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group	2.3	0.91	B++	B
Avera Proxy Group	2.2	0.97	B++	B+
Pinnacle West Capital	1.0	1.00	A	B

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

SUMMARY OF UPDATES OF COST OF CAPITAL ANALYSES
TESTIMONY OF DAVID C. PARCELL
ON BEHALF OF COMMISSION STAFF

	Direct Testimony	Update	Change
Interest Rates -- Latest Month			
US Treasury Bills 3 Month	4.79%	4.82%	0.03%
US Treasury Bonds 10 Year	5.11%	4.72%	-0.39%
Utility Bonds Aa	6.16%	5.81%	-0.35%
Utility Bonds A	6.40%	6.00%	-0.40%
Utility Bonds Baa	6.61%	6.26%	-0.35%
DCF Analysis			
Comparison Group			
Dividend Yield	4.5%	4.3%	-0.2%
Projected Retention Rate	2.8%	2.7%	-0.1%
Projected Per Share Growth	3.9%	3.8%	-0.1%
First Call EPS Growth	5.4%	5.9%	0.5%
DCF Average	8.1%	8.0%	-0.1%
DCF Median	8.4%	8.3%	-0.1%
DCF High	10.0%	10.3%	0.3%
Avera Group			
Dividend Yield	3.6%	3.5%	-0.1%
Projected Retention Rate	4.8%	4.8%	0.0%
Projected Per Share Growth	5.0%	5.2%	0.2%
First Call EPS Growth	5.9%	6.0%	0.1%
DCF Average	8.9%	8.9%	0.0%
DCF Median	8.8%	8.9%	0.1%
DCF High	9.6%	9.5%	-0.1%
CAPM Analysis			
Risk Free Rate	5.30%	4.99%	-0.31%
Risk Premium	5.80%	5.90%	0.10%
Comparison Group			
Beta	0.89	0.91	0.02
CAPM Average	10.4%	10.4%	0.0%
CAPM Median	10.5%	10.3%	-0.2%
Avera Group			
Beta	0.93	0.97	0.04
CAPM Average	10.7%	10.7%	0.0%
CAPM Median	10.8%	10.9%	0.1%
Comparable Earnings Analysis			
Projected ROE			
Comparison Group			
2006	8.2%	8.3%	0.1%
2007	8.7%	8.6%	-0.1%
2009-2011	9.3%	9.4%	0.1%
Avera Group			
2006	10.4%	10.3%	-0.1%
2007	10.1%	10.1%	0.0%
2009-2011	9.9%	10.0%	0.1%

EXHIBIT 5-11 admitted

PINNACLE WEST NYSE-PNW

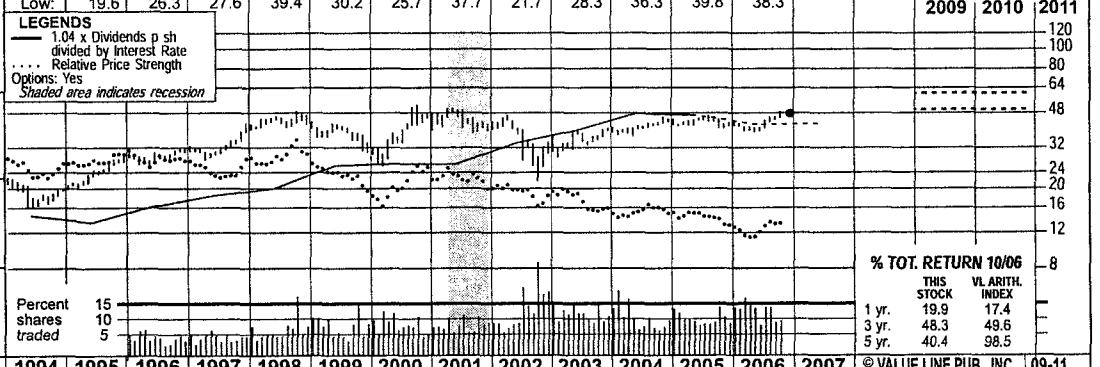
RECENT PRICE 47.81 | P/E RATIO 13.2 (Trailing: 14.4 Median: 13.0) | RELATIVE P/E RATIO 0.72 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 2 Raised 11/10/06
SAFETY 1 Raised 5/16/03
TECHNICAL 2 Raised 9/22/06
BETA 1.00 (1.00 = Market)

High:	28.9	32.3	42.8	49.3	43.4	52.7	50.7	46.7	40.5	45.8	46.7	48.9
Low:	19.6	26.3	27.6	39.4	30.2	25.7	37.7	21.7	28.3	36.3	39.8	38.3

Target Price Range 2009 | 2010 | 2011

LEGENDS
— 1.04 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+25%)	10%
Low	50	(+5%)	6%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	2	2	0	0
Options	0	0	0	0	0	0	2	6	2
to Sell	0	0	0	0	0	2	1	6	2

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	159	137	132
to Sell	100	118	115
Hld's(000)	76236	75120	80731

Percent shares traded 15 10 5

% TOT. RETURN 10/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	19.9	17.4
3 yr.	48.3	49.6
5 yr.	40.4	98.5

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
18.38	16.95	19.39	19.66	19.28	19.08	20.77	23.52	25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.16	*34.75*	*37.65*	Revenues per sh	*42.90*
3.27	d1.39	4.70	5.25	5.09	5.16	5.90	7.12	7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	*7.35*	*8.20*	"Cash Flow" per sh	*10.10*
.81	d3.90	1.73	1.95	1.99	2.22	2.47	2.76	2.85	3.18	3.35	3.68	2.53	2.52	2.58	2.31	*3.35*	*3.60*	Earnings per sh A	*3.70*
--	--	--	.20	.83	.93	1.03	1.13	1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	*2.03*	*2.13*	Div'd Decl'd per sh B■†	*2.43*
2.98	2.10	2.57	2.69	2.92	3.38	2.95	3.63	3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	*8.90*	*8.60*	Cap'l Spending per sh	*8.00*
17.40	15.23	17.00	18.87	20.32	21.49	22.51	23.90	25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	*35.70*	*37.20*	Book Value per sh C	*41.05*
86.87	87.01	87.16	87.42	87.43	87.52	87.52	84.83	84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.08	*99.60*	*99.60*	Common Shs Outst'g D	*100.00*
16.3	--	10.8	11.5	9.6	10.8	11.8	11.8	15.2	11.9	11.3	12.0	14.4	14.0	15.8	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
1.21	--	.66	.68	.63	.72	.74	.68	.79	.68	.73	.61	.79	.80	.83	1.00	*Value Line*		Relative P/E Ratio	*.95*
--	--	--	.9%	4.3%	3.9%	3.5%	3.5%	2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*

CAPITAL STRUCTURE as of 6/30/06
Total Debt $3075.3 mill. **Due in 5 Yrs** $598.9 mill.
LT Debt $2815.7 mill. **LT Interest** $175.0 mill.
(LT interest earned: 2.6x)

Pension Assets-12/05 $1.06 bill. **Oblig.** $1.60 bill.

Pfd Stock None

Common Stock 99,477,663 shs. **as of 8/4/06**
MARKET CAP: $4.8 billion (Mid Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
1817.8	1995.0	2130.6	2423.4	3690.2	4551.4	2637.3	2817.9	2899.7	2988.0	*3460*	*3750*	Revenues ($mill) F	*4290*
198.3	248.7	252.6	270.8	283.6	312.2	215.2	230.6	235.2	223.2	*335*	*360*	Net Profit ($mill)	*370*
39.3%	37.7%	39.5%	38.3%	44.1%	40.6%	39.1%	31.4%	35.4%	36.2%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
7.4%	6.5%	7.4%	4.3%	7.6%	15.3%	20.5%	6.2%	6.9%	10.4%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*4.0%*
52.0%	50.5%	47.6%	50.0%	45.1%	51.7%	51.8%	50.6%	46.7%	43.2%	*43.0%*	*44.0%*	Long-Term Debt Ratio	*46.0%*
43.2%	45.6%	50.2%	50.0%	54.9%	48.3%	48.2%	49.4%	53.3%	56.8%	*57.0%*	*56.0%*	Common Equity Ratio	*54.0%*
4561.1	4442.9	4307.6	4411.8	4337.8	5172.4	5567.9	5727.5	5535.2	6033.4	*6260*	*6605*	Total Capital ($mill)	*7605*
4655.1	4677.6	4730.6	4778.5	5133.2	5907.3	6479.4	7480.1	7535.5	7577.1	*8025*	*8425*	Net Plant ($mill)	*9365*
6.2%	7.4%	7.6%	7.9%	8.1%	7.6%	5.4%	5.5%	5.6%	5.0%	*6.5%*	*7.0%*	Return on Total Cap'l	*6.5%*
9.1%	11.3%	11.2%	12.3%	11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	*9.5%*	*9.5%*	*Return on Shr. Equity*	*9.0%*
9.2%	11.6%	11.2%	12.2%	11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	*9.5%*	*9.5%*	Return on Com Equity E	*9.0%*
4.6%	6.9%	6.4%	7.1%	6.8%	7.3%	2.9%	2.6%	2.3%	1.0%	*3.5%*	*4.0%*	Retained to Com Eq	*3.0%*
54%	44%	45%	42%	43%	41%	64%	68%	71%	85%	*60%*	*59%*	All Div'ds to Net Prof	*65%*

ELECTRIC OPERATING STATISTICS

	2003	2004	2005
% Change Retail Sales (KWH)	+5.1	+3.2	+4.4
Avg. Indust. Use (MWH)	695	707	670
Avg. Indust. Revs. per KWH (¢)	5.62	5.57	6.28
Capacity at Peak (Mw)	7935	7758	7412
Peak Load, Summer (Mw)	6332	6402	7000
Annual Load Factor (%)	50.9	52.2	50.0
% Change Customers (yr-end)	+3.3	+3.7	+4.3
Fixed Charge Cov. (%)	250	261	278

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	5.0%	-1.0%	*5.5%*
"Cash Flow"	2.5%	-3.0%	*7.0%*
Earnings	2.0%	-4.5%	*7.0%*
Dividends	11.0%	6.5%	*5.0%*
Book Value	5.0%	4.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	552.7	683.3	847.7	734.2	2817.9
2004	566.3	711.9	886.8	734.7	2899.7
2005	585.0	755.8	955.6	691.6	2988.0
2006	670.2	925.0	1076.4	*788.4*	*3460*
2007	*750*	*1000*	*1150*	*850*	*3750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.22	.60	1.20	.50	2.52
2004	.34	.78	1.14	.32	2.58
2005	.26	.88	.86	.24	2.24
2006	.12	1.11	1.84	*.28*	*3.35*
2007	*.40*	*1.25*	*1.40*	*.55*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.40	.40	.40	.425	1.63
2003	.425	.425	.425	.45	1.73
2004	.45	.45	.45	.475	1.83
2005	.475	.475	.475	.50	1.93
2006	.50	.50	.50		

BUSINESS: Pinnacle West Capital Corporation (parent of Arizona Public Service) supplies electricity to approx. 1,780,000 people in 11 of 15 Arizona counties. Electric revenue sources: residential, 50%; commercial, industrial, and other, 50%. Power costs: 38% of electric revenues; labor costs: 13% of total revenues. The mining industry is the largest industrial customer. Energy sources: coal, 26%; nuclear, 15%; gas & other, 7%; purch. power, 52%. Has 7,300 employees. Reported '05 depreciation rate: 3.0%. Est'd plant age: 10 years. Chairman & Chief Executive Officer: William J. Post. Pres.: Jack E. Davis. Inc.: Arizona. Address: 400 E. Van Buren St., Suite 700, P.O. Box 52132, Phoenix, AZ 85072-2132. Tel.: 602-379-2568. Internet: www.pinnaclewest.com.

Pinnacle West's application for higher electric rates is in the hopper. The filing for $493.9 million assumes a capital structure of 45% debt and 55% equity, as well as an 11.50% allowed return on common, up from the present 10.25%. The chief component of the request is $299 million for increased fuel and purchased-power costs and modifications in the previously approved power supply adjuster. The proposal also seeks higher base rates for the acquisition of the 450-megawatt (mw) Sundance plant, accelerated funding for the underfunded pension plan, and a surcharge for environmental improvements. The commission staff has recommended an increase of only $208.3 million. A regulatory order on the petition is due early next year. Whatever amount is granted will take effect next January 1st.

The company has issued requests for power. To help meet rising customer demand, it asked prospective providers to submit offers for baseload capacity of 100 mw to 500 mw per unit. It will consider multiunits at a single site with phased-in service dates. Some of the generation must be available as early as 2009, all by 2014. The power must exclude or substantially limit exposure to natural gas supply and price risk. The plants must have the ability to operate at an annual capacity factor of 85% and higher than 95% during the summer. Management will consider equity ownership or purchased-power contracts with options to extend the agreements.

Earnings should rise to a five-year high in 2006. PNW will benefit from two power supply adjuster increases totaling $259 million that took effect earlier this year. Other pluses include a full year of the March, 2005 rate hike of $75.5 million and the end of losses on the recently sold Silverhawk gas-fired unit. Despite higher fuel costs resulting from the Palo Verde 1 nuclear plant outage, we estimate a 50% gain in this year's earnings, to $3.35 a share. An order on the pending rate case suggests further improvement in 2007.

Utility investors might take a look at this timely stock. Projected earnings growth to 2009-2011 should support above-average dividend hikes over that period. Too, these shares are of good quality.

Arthur H. Medalie *November 10, 2006*

(A) Diluted egs. '05 egs. don't equal array due to change no. shs. Excl. nonrecur.: '91, ($4.68); '93, 22¢; '94, 31¢; '95, net 6¢; '99, ($1.20); '02, (77¢); excl. discont.: '90, 31¢; '91, $1.76; '92, 7¢; '99, ($1.97); '00, 22¢; '05, (36¢). Next egs. rpt. due late Jan. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Divd reinvest. plan avail. † Shholder invest. plan avail. (C) Incl. def. chgs. In '05: $4.64/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in '05: 10.25%; earn. on avg. com. eq. in '05: 7.0%. Regul. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	65

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EXHIBIT
S-12
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
BARRY WONG
Commissioner

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 TO AMEND DECISION NO. 67744.	)	DOCKET NO. E-01345A-05-0816

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 18, 2006

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1. Resume of Barbara Keene

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

This testimony makes recommendations regarding funding for renewable resources, net metering, and green pricing tariffs. Those recommendations are the following:

1. The amount for renewables in System Benefits should continue to be $6,000,000.
2. The Environmental Portfolio Standard adjustor rate and caps should be increased to recover an additional $4.25 million for the EPS Credit Purchase Program.
3. The proposed net metering tariff, EPR-5, should be approved with the following modifications:
   a. A bi-directional meter should not be required.
   b. The limit on facility size should be increased to 100 kW.
   c. The participation of customers should not be limited by rate schedule.
   d. In the definition of Pilot Program, the phrase "with Commission approval" should be added to the end of the sentence that indicates that APS reserves the right to modify the rate schedule.
4. Green Power Block Schedule (GPS-1) and Green Power Percent Schedule (GSP-2) should be approved as proposed by APS.

This testimony also responds to Commissioner Mayes' July 17, 2006, letter regarding the Renewable Energy Standard and Tariff.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst Manager. My duties include supervising the energy portion of the Telecommunications and Energy Section. A copy of my résumé is provided in Appendix 1.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket Nos. E-01345A-05-0816?

A. Yes.

Q. What is the subject matter of your testimony?

A. My testimony will address renewable energy for Arizona Public Service ("APS"); in particular, funding for renewable resources, net metering, and green pricing tariffs. This testimony also responds to Commissioner Mayes' July 17, 2006, letter regarding the Renewable Energy Standard and Tariff ("REST").

FUNDING FOR RENEWABLE RESOURCES

Q. What is the Environmental Portfolio Standard?

A. The Environmental Portfolio Standard ("EPS"), embodied in A.A.C. R14-2-1618, was approved by the Commission in 2001. The EPS requires load-serving entities to derive a portion of the retail energy they sell from solar resources or environmentally friendly

renewable electricity technologies. The portfolio percentage increases annually. It was 1.00 percent in 2005 and became 1.05 percent in 2006, with at least 60 percent from solar resources.

Q. Did APS meet its EPS requirement in 2005?

A. No. According to APS' annual EPS report required under A.A.C. R14-2-1618(D), APS' total retail sales in 2005 totaled 26,477,551 MWh. Because the EPS requirement was 1.00 percent in 2005, APS was required to provide 1.00 percent of its retail sales from renewable resources. Therefore, the EPS target was 264,776 MWh (1.00 percent of 26,477,551 MWh). Since APS had 36,958 MWh from renewable resources in 2005, it met 14 percent of its 2005 EPS requirement (36,958 MWh = 14 percent of 264,776 MWh).

Q. What did APS do in regard to renewable resources in 2005?

A. During 2005, APS installed new solar generation capacity (both photovoltaic and solar trough); awarded contracts for wind, biomass, and biogas resources; provided off-grid solar services, continued its Solar Partners "green pricing" program; explored development of geothermal and manure resources; offered the EPS Credit Purchase Program; and purchased EPS credits from other providers.

Q. How is the EPS funded?

A. The costs of the EPS are recovered through the System Benefits Charge and through the Environmental Portfolio Surcharge, approved by Decision No. 63354 on February 8, 2001, and established as an adjustment mechanism by Decision No. 67744 (APS rate case settlement agreement). The surcharge is currently set at $0.000875 per kWh with monthly

caps per service of $0.35 for residential customers, $13.00 for non-residential customers, and $39.00 for non-residential customers with demands of 3,000 kW or more.

Q. How much funding did APS have for renewable resources in 2005?

A. In 2005, APS received a total of $13,780,276 in revenue for renewable resources, including $7,320,775 through the EPS adjustor, $6,000,000 in System Benefits, $285,345 from its Solar Partners program, and $174,156 from off-grid revenue. During the test year, APS received $7,229,172 through the EPS adjustor. Total expenditures for renewable resources in 2005 were $14,039,708.

Q. What does Staff recommend regarding funding for renewables in the System Benefits Charge?

A. There is currently $6,000,000 for renewables in the System Benefits Charge. Staff recommends that the amount continue to be $6,000,000.

<u>EPS Credit Purchase Program</u>

Q. Please describe the EPS Credit Purchase Program.

A. APS began its EPS Credit Purchase Program in 2002. Through the program, customers install renewable energy systems on their properties, and APS reimburses them for a portion of the costs of the systems. APS can then use the renewable energy credits associated with the systems to help meet its EPS requirements.

Q. What needs to be done regarding funding for the EPS Credit Purchase Program?

A. Decision No. 67744 provided that renewable programs that directly involve APS retail customers must be submitted to the Commission for approval. When the Commission approved the EPS Credit Purchase Program in Decision No. 68668 (April 20, 2006), APS

was ordered to increase its allocation for the program by an additional $4.25 million. Decision No. 68668 ordered that "any additional funds put into the credit purchase program by APS at the direction of the Commission shall be recovered in rates as part of APS' ongoing general rate case."

Q. How does Staff propose to handle the additional $4.25 million allocation in the rate case?

A. Staff recommends that the EPS adjustor rate and caps be increased to recover an additional $4.25 million. The increased rate and caps will be discussed in Staff rate design testimony to be filed on September 1, 2006.

NET METERING

Q. What is net metering?

A. Net metering allows customers to use their own generation to offset their consumption over a billing period. In effect, customers receive retail prices for the electricity they generate. Without net metering, the utility purchases the electricity that flows to the utility at its avoided cost for generating or acquiring electricity in the wholesale market. According to the U.S. Department of Energy Green Power Network, net metering is offered in more than 35 states.

Q. What has APS proposed in regard to net metering?

A. APS has proposed a new rate schedule EPR-5, Rates for Renewable Resource Facilities of 10 kW or Less for Partial Requirements.

Q. How are renewable projects currently compensated for electricity that flows to the utility?

A. Customers with those projects are compensated through the purchase rates included on EPR-2 (100 kW or less) or EPR-4 (10 kW or less). The purchase rates, updated annually, are the same on both schedules and are based on APS' estimated avoided energy costs. EPR-2 contains a monthly service charge.

Q. Please describe EPR-5.

A. EPR-5 would be a three-year pilot program for renewable resource generation facilities with a nameplate rating of 10 kW or less. A bi-directional meter would be provided to a customer. The customer would receive the full retail value of the energy component (charges assessed on a kWh basis) of its bundled Standard Offer Service Rate for the power fed into the system from the customer's generator. When the customer-owned generation output exceeds the customer's total usage in a given month, the customer would receive a kWh credit for the excess generation output on the next monthly bill. Any remaining kWh credit amount would be zeroed out in the customer's last bill of the calendar year or when the customer is shut off.

Eligible renewable resources would be those resources included in the EPS rules as may be modified. Retail rate schedules under the program would be limited to E-12, ET-1, ET-2, ECT-1R, and ECT-2 for residential customers and E-32 and E-32TOU for general service customers with monthly maximum demands of 20 kW or less. The pilot program would be capped at a total of 15 MW of capacity.

EPS funding would be used to recover the metering costs, billing system modification cost, and revenue loss associated with the program. According to APS' response to data

request BEK 8-4, APS estimates the billing system modification cost to be about $848,500 and take about six to eight months to implement. Revenue loss would be calculated as the per kWh charges of the retail rate less APS' avoided fuel and purchased power cost.

Q. What does Staff recommend in regard to the proposed EPR-5?

A. Staff recommends approval of EPR-5 with modifications.

Q. What are Staff's proposed modifications to EPR-5?

A. The first modification is that a bi-directional meter not be required. Two standard meters (one measuring electricity going out and one measuring electricity coming in) could be used at lower cost than for a bi-directional meter. Per APS' response to data request BEK 8-2, the total installed cost for a bi-directional meter is $483.30 with maintenance cost of $15.97 per year. The installed cost of a standard meter is $102.63 and $1.18 per year for maintenance. Since one meter would already be in place, the savings from using two standard meters in place of a bi-directional meter would be $380.67 for each installed meter and $14.79 per year for maintenance of each meter.

In addition, the proposed EPR-5 contains a statement that "The Company" would provide a meter. APS should modify the statement to indicate that a meter would be provided but not imply that ratepayers would not be paying for it.

Q. Should APS recover "revenue loss" associated with the program through EPS funds?

A. Yes. APS should recover revenue loss associated with the program through EPS funds. This situation is analogous to when APS contracts to buy renewable energy in the wholesale market. The costs of the renewable energy that are below or at the market price

of conventional generation are included in the calculations of the Power Supply Adjustor. APS is allowed to recover the amount above the market price of conventional generation through EPS funds.

Q. Does Staff agree with the method that APS proposes to use to calculate the revenue loss?

A. Yes. APS described the method of calculation in response to Staff's data request BEK 8-5. The lost revenues would be derived by applying the average kWh charges in the customer's otherwise applicable rate schedule to the kWh loss. The kWh charges would be for all services, including the EPS adjustor.

Q. Does Staff agree with the 10 kW limit on facility size?

A. No. Staff recommends that the limit on facility size be increased to 100 kW. This would allow larger projects to participate, while continuing to not allow a few projects to consume all of the funds.

Q. Does Staff agree with APS that only customers on specific rate schedules should be allowed to participate in the program?

A. No. Staff recommends that participation of customers should not be limited by rate schedule.

Q. Does Staff propose any other modifications to EPR-5?

A. Yes. In the definition of Pilot Program on EPR-5, APS indicates that it reserves the right to modify the rate schedule. The phrase "with Commission approval" should be added to the end of the sentence.

GREEN PRICING TARIFFS

Q. What is green pricing?

A. According to the U. S. Department of Energy Green Power Network, green pricing is an optional service that allows customers an opportunity to voluntarily support a greater level of investment in renewable energy technologies. Participating customers pay a premium on their electric bills to cover the incremental cost of the additional renewable energy. More than 600 utilities in the country offer a green pricing option.

Q. Does APS currently have a green pricing program?

A. Yes. APS has offered its Solar Partners Program (SP-1) since 1997. Through the program, customers pay a premium of $2.64 per month for a block of 15 kWh of solar energy. This equates to $0.176 per kWh in addition to the customer's current rate schedule.

Q. What has APS proposed in regard to green pricing?

A. APS has proposed freezing SP-1 and replacing it with two new rate schedules, Green Power Block Schedule (GPS-1) and Green Power Percent Schedule (GSP-2).

Q. Please describe GPS-1.

A. GPS-1 is similar to SP-1 in that customers would have the opportunity to buy blocks of electricity generated from renewable resources. The price would be $0.75 per month for each 25 kWh block. This equates to $0.03 per kWh in addition to the customer's current rate schedule. According to APS' response to Western Resource Advocates' data request WRA 1-1, the price represents the projected net cost of renewable energy above the cost of the conventional resource alternative. The renewable resources would include those resources eligible under the EPS rules as they are modified.

Q. Please describe GPS-2.

A. Under GPS-2, customers would choose a percentage of their electricity usage to come from renewable resources. There would be four options: $0.03 per kWh for 100 percent of the customer's service from renewable energy, $0.015 per kWh for 50 percent of the customer's service from renewable energy, $0.009 per kWh for 30 percent of the customer's service from renewable energy, and $0.003 per kWh for 10 percent from renewable energy. These prices would be in addition to the customer's current rate schedule. In effect, the prices all equate to $0.03 for a kWh of renewable energy.

Q. What does Staff recommend regarding GPS-1 and GPS-2?

A. Staff recommends that GPS-1 and GPS-2 be approved as proposed by APS.

RESPONSE TO COMMISSIONER MAYES' JULY 17, 2006 LETTER

Q. What did Commissioner Mayes request in her July 17, 2006, letter?

A. Commissioner Mayes requested that the parties to this Docket provide testimony on incorporating the Renewable Energy Standard and Tariff ("REST") into this case.

Q. What is the REST?

A. The proposed REST rules are intended to replace the current EPS rules. The Commission, in Decision No. 68566 (March 14, 2006), ordered that a rulemaking process begin for the REST rules.

Q. If the REST rules were to become effective, what would it mean for APS?

A. APS would have to comply with specific requirements regarding renewable resources.

Q. What are the requirements that APS would have to follow?

A. The requirements of the REST rules, in their present form, are the following:

1. APS would meet an Annual Renewable Energy Requirement by obtaining Renewable Energy Credits. A Renewable Energy Credit would be created for each kWh derived from an Eligible Energy Resource.

2. The Annual Renewable Energy Requirement would be calculated each calendar year by applying the applicable annual percentage in the following table to the retail kWh sold by APS during that calendar year.

Table 1
Annual Renewable Energy Requirement

Calendar Year	Annual Percentage of Retail kWh Sales
2007	1.50
2008	1.75
2009	2.00
2010	2.50
2011	3.00
2012	3.50
2013	4.00
2014	4.50
2015	5.00
2016	6.00
2017	7.00
2018	8.00
2019	9.00
2020	10.00
2021	11.00
2022	12.00
2023	13.00
2024	14.00
After 2024	15.00

3. A percentage of the above annual requirements would come from Distributed Renewable Energy Resources as shown in the following table. Half of the

Distributed Renewable Requirement would come from residential applications and the remaining half from non-residential, non-utility applications. No more than 10 percent would come from non-utility owned generators that sell electricity at wholesale to utilities subject to the EPS rules.

Table 2
Distributed Renewable Energy Requirement

Calendar Year	Distributed Percentage of Annual Renewable Energy Requirement
2007	5
2008	10
2009	15
2010	20
2011	25
After 2011	30

4. Eligible Energy Resources would be applications of the following technologies:

a. biogas electricity generators;

b. biomass electricity generators;

c. hydropower facilities that were in existence prior to 1997 and have either a capacity increase or are used to firm or regulate the output of other eligible, intermittent renewable resources;

d. new hydropower generators of 10 MW or less;

e. fuel cells that use only renewable fuels;

f. geothermal generators;

g. hybrid wind and solar electric generators;

h. landfill gas generators;

i. solar electricity resources;

j. wind generators; and

k. Distributed Renewable Energy Resources.

5. Distributed Renewable Energy Resources would be applications of the following technologies that are located at a customer's premises:

a. biogas electricity generators;

b. biomass electricity generators;

c. geothermal generators;

d. fuel cells that use only renewable fuels;

e. new hydropower generators of 10 MW or less;

f. solar electricity resources;

g. commercial solar pool heaters;

h. geothermal space heating and process heating systems;

i. renewable combined heat and power systems;

j. solar daylighting;

k. solar heating, ventilation, and air conditioning;

l. biomass thermal systems;

m. biogas thermal systems;

n. solar industrial process heating and cooling;

o. solar space cooling;

p. solar space heating;

q. solar water heaters; and

r. wind generators of 1 MW or less.

6. For Distributed Renewable Energy Resources, one Renewable Energy Credit would be created for each 3,415 British Thermal Units of heat produced by technologies listed in number 5.l-q above.

7. Up to 20 percent of an Annual Renewable Energy Requirement could be met with Renewable Energy Credits derived from "manufacturing partial credits" if APS or an affiliate made a significant investment in a solar electric manufacturing plant located in Arizona or provided incentives to locate a solar electric manufacturing facility in Arizona. The credits would be equal to the nameplate capacity of the solar electric generators produced and sold in a calendar year times 2,190 hours.
8. Extra credit multipliers as included in the EPS rules would not be applicable for Eligible Renewable Energy Resources installed after December 31, 2005.
9. APS could ask the Commission to preapprove agreements to purchase energy or Renewable Energy Credits from Eligible Energy Resources.
10. APS would develop a customer self-directed renewable energy option.
11. APS would file annual reports.

Q. How would the EPS Adjustor rates be changed for APS to meet those requirements.

A. In response to Staff's data request BEK 12-3, APS has estimated that the rate and caps contained in the Sample Tariff (within the REST rules) would have resulted in revenue of about $28.52 million in 2005. The Sample Tariff consists of a monthly assessment of $0.004988 per kWh with monthly caps per service of $1.05 for residential customers, $39.00 for non-residential customers, and $117.00 for non-residential customers with demands of 3,000 kW or more. However, this rate and these caps would not be used for APS.

Q. Why would APS use a different rate and different caps than those contained in the Sample Tariff?

A. Paragraph 63 of the settlement agreement approved by Decision No. 67744 provides that any change in EPS funding requirements shall be collected from APS' customers in a

manner that maintains the proportions between customer categories embodied in the current EPS surcharge. The proposed rate in the Sample Tariff would be 5.7 times the current rate, and the proposed caps would be 3 times the current caps. Maintaining the proportions between customer categories requires that the rate and caps be multiplied by the same number.

Q. How would the rate and caps be set so as to maintain the proportions between customer categories?

A. APS has estimated, in response to Staff's data request BEK 12-4, that multiplying the current rate and caps by 3.8 would result in a similar level of revenue ($28.59 million) and maintain the proportions between customer categories.

Q. How much of an increase over current EPS revenues would result from the changes to the rate and caps?

A. Complying with the proposed REST rules would require an increase of about $21.36 million over current EPS revenue.

Q. What would be the resulting rate and caps?

A. The rate would be $0.003325 per kWh with monthly caps per service of $1.33 for residential customers, $49.40 for non-residential customers, and $148.00 for non-residential customers with demands of 3,000 kW or more. The EPS Adjustor would be modified to incorporate this rate and these caps.

Q. Would there be any other cost recovery considerations?

A. Yes. The EPS adjustor would recover only the costs of renewable resources in excess of the market cost of conventional generation. In addition, APS could apply to the

Commission to increase its EPS funding as outlined in paragraph 64 of the settlement agreement approved by Decision No. 67744.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. The amount for renewables in System Benefits should continue to be $6,000,000.
2. The EPS adjustor rate and caps should be increased to recover an additional $4.25 million for the EPS Credit Purchase Program.
3. EPR-5 should be approved with the following modifications:
   a. A bi-directional meter should not be required.
   b. The limit on facility size should be increased to 100 kW.
   c. The participation of customers should not be limited by rate schedule.
   d. In the definition of Pilot Program, the phrase "with Commission approval" should be added to the end of the sentence that indicates that APS reserves the right to modify the rate schedule.
4. GPS-1 and GPS-2 should be approved as proposed by APS.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on ratemaking, energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst Manager (May 2005-present). Supervise the energy portion of the Telecommunications and Energy Section. Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-present), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Generic Proceeding Concerning Electric Restructuring Issues (Docket No. E-00000A-02-0051), Arizona Corporation Commission, 2002; testimony on affiliate relationships and codes of conduct.

Tucson Electric Power Company's Application for Approval of New Partial Requirements Service Tariffs, Modification of Existing Partial Requirements Service Tariff 101, and Elimination of Qualifying Facility Tariffs (Docket No. E-01933A-02-0345) and Application for Approval of its Stranded Cost Recovery (Docket No. E-01933A-98-0471), Arizona Corporation Commission, 2002, testimony on proposals to eliminate, modify, or introduce tariffs and testimony on the modification of the Market Generation Credit.

Arizona Public Service Company's Application for Approval of Adjustment Mechanisms (Docket No. E-01345A-02-0403), Arizona Corporation Commission, 2003, testimony on the proposed Power Supply Adjustment and the proposed Competition Rules Compliance Charge.

Generic Proceeding Concerning Electric Restructuring Issues, et al (Docket No. E-00000A-02-0051, et al), Arizona Corporation Commission, 2003-2005; Staff Report and testimony on Code of Conduct.

Arizona Public Service Company Rate Case (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004; testimony on demand-side management, system benefits, renewable energy, the Returning Customer Direct Assignment Charge, and service schedules.

Arizona Electric Power Cooperative Rate Case (Docket No. E-01773A-04-0528), Arizona Corporation Commission, 2005; testimony on a fuel and purchased power cost adjustor, demand-side management, and rate design.

Trico Electric Cooperative Rate Case (Docket No. E-01461A-04-0607), Arizona Corporation Commission, 2005; testimony on the Environmental Portfolio Standard; demand-side management; special charges; and Rules, Regulations, and Line Extension Policies.

Arizona Public Service Company (Docket Nos. E-01345A-03-0437 and E-01345A-05-0526), Arizona Corporation Commission, 2005; testimony on the Plan of Administration of the Power Supply Adjustor.

Arizona Public Service Company Emergency Rate Case (Docket No. E-01345A-06-0009), Arizona Corporation Commission, 2006; testimony on bill impacts.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees*. Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

"DSM Workshop Progress Report," Arizona Corporation Commission, 2004.

(with Erin Casper) "Staff Report on Demand Side Management Policy," Arizona Corporation Commission, 2005.

EXHIBIT
S-13
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
BARRY WONG
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUEOF 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 TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816

RATE DESIGN

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEMBER 1, 2006

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

This testimony recommends the following:

1. The EPS adjustor rate and caps should be increased to recover an additional $4.25 million for the EPS Credit Purchase Program.

2. The EPS adjustor rate should be set at $0.001392 per kWh with monthly caps per service of $0.56 for residential customers, $20.68 for non-residential customers, and $62.04 for non-residential customers with demands of 3,000 kW or more.

3. The $17,639,421 associated with Palo Verde outages that Staff has recommended to be disallowed should be removed from the Paragraph 19(d) Balancing Account and not be recovered from ratepayers. The exact amount of the disallowance would have to be determined at the time of the Decision because interest would continue to accrue until the effective date of the Decision.

4. Staff recommends that APS be allowed to recover the remaining balance in the Paragraph 19(d) Balancing Account through a surcharge. The surcharge rate would be about $0.001029 per kWh, assuming that the amount to be recovered would be amortized over one year. However, the final surcharge rate will depend on how much interest has accrued by the time of the Decision in this case and on updated forecasts of kWh sales.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony addressing renewable energy for Arizona Public Service ("APS"); in particular, funding for renewable resources, net metering, and green pricing tariffs. That testimony also responded to Commissioner Mayes' July 17, 2006, letter regarding the Renewable Energy Standard and Tariff ("REST").

Q. What is the subject matter of your rate design testimony?

A. My testimony will address a change in the Environmental Portfolio Standard ("EPS") adjustor rate for Arizona Public Service ("APS") to recover costs for the EPS Credit Purchase Program, and the establishment of a Power Supply Adjustor surcharge to recover costs associated with nuclear plant outages that have not been found to be imprudent.

CHANGE IN THE EPS ADJUSTOR RATE

Q. What is the Environmental Portfolio Standard?

A. As discussed in Staff's direct testimony, the Environmental Portfolio Standard ("EPS"), embodied in A.A.C. R14-2-1618, requires load-serving entities to derive a portion of the retail energy they sell from solar resources or environmentally friendly renewable electricity technologies.

Q. How is the EPS funded?

A. The costs of the EPS are recovered through the System Benefits Charge and through the Environmental Portfolio Surcharge, approved by Decision No. 63354 on February 8, 2001, and established as an adjustment mechanism by Decision No. 67744 (APS rate case settlement agreement). The surcharge is currently set at $0.000875 per kWh with monthly caps per service of $0.35 for residential customers, $13.00 for non-residential customers, and $39.00 for non-residential customers with demands of 3,000 kW or more.

Q. How much funding did APS receive through the EPS adjustor during the test year?

A. During the test year, APS received $7.2 million through the EPS adjustor.

Q. What does Staff recommend regarding the EPS adjustor?

A. Staff recommends that the EPS adjustor rate and caps be increased to allow for more funding of the EPS Credit Purchase Program.

Q. Please describe the EPS Credit Purchase Program.

A. As described in Staff's direct testimony, APS' EPS Credit Purchase Program reimburses customers for a portion of the costs of renewable energy systems installed on their properties. APS can then use the renewable energy credits associated with the systems to help meet its EPS requirements.

Q. What needs to be done regarding funding for the EPS Credit Purchase Program?

A. Decision No. 68668 (April 20, 2006), provided that APS was to increase its allocation for the program by an additional $4.25 million and that any additional funds put into the credit purchase program by APS at the direction of the Commission would be recovered in rates as part of APS' ongoing general rate case.

Q. How should the EPS adjustor rates be changed to recover the additional $4.25 million?

A. In response to Staff's data request BEK 18-1, APS has estimated that the rate and caps would change as follows in order to collect an additional $4.25 million and maintain the proportions between customer classes:

Rate: $0.001392 per kWh

Caps: $0.56 per residential service per month

$20.68 per non-residential service per month

$62.04 per non-residential service with demands of more than 3,000 kW

Q. Why should the proportions between customer classes be maintained?

A. As discussed in Staff's direct testimony, paragraph 63 of the settlement agreement approved by Decision No. 67744 provides that any change in EPS funding requirements shall be collected from APS' customers in a manner that maintains the proportions between customer categories embodied in the current EPS surcharge. Maintaining the proportions between customer categories requires that the rate and caps be multiplied by the same number. In this case, the rate and caps would be multiplied by an estimated 1.5907 to achieve total funding through the EPS adjustor of $11.45 million ($7.2 million plus $4.25 million).

ESTABLISHMENT OF A POWER SUPPLY ADJUSTOR SURCHARGE

Q. Please describe the Power Supply Adjustor ("PSA").

A. The PSA, established by Decision No. 67744, tracks changes in APS' cost of obtaining power supplies and allows APS to recover or refund changes in its fuel and purchased power costs. The annual adjustor rate is reset on each February 1 with a $0.004 limit over the term of the PSA. Decision No. 68437 provides that any amount outside the $0.004

bandwidth is put into a "Paragraph 19(d) Balancing Account." Surcharges may be approved by the Commission to recover or refund amounts in the Paragraph 19(d) Balancing Account. An amount approved for collection through a surcharge is removed from the Paragraph 19(d) Balancing Account and placed in a Surcharge Account to record collections through the surcharge and calculate the balance remaining to be collected. Each month, interest is applied to all of the PSA accounts, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, on the first business day of the calendar year.

Q. What is currently in the Paragraph 19(d) Balancing Account?

A. After the February 2006 reset of the adjustor rate, $59,858,187 was entered into the Paragraph 19(d) Balancing Account. Decision No. 68646 authorized a surcharge to recover $15.3 million, beginning in May 2006. Therefore, $15.3 million was removed from the Paragraph 19(d) Balancing Account and placed in a Surcharge Account. The balance in the Paragraph 19(d) Balancing Account, plus interest, relates to costs associated with outages of the Palo Verde Nuclear Generating Station ("Palo Verde"). Decision No. 68646 stated that it was premature to grant a surcharge on those costs at that time in light of the Commission's on-going inquiry regarding unplanned 2005 outages at Palo Verde.

Q. What has Staff recommended in regard to those costs associated with Palo Verde outages?

A. Staff witness William R. Jacobs summarized in his direct testimony the conclusions and recommendations made in the report concerning the operation of Palo Verde in 2005 filed in Docket No. E-01345A-05-0826. One of the recommendations was that the Commission should disallow the costs resulting from outages identified as avoidable and imprudent. The amount (including the cost of replacement power, lost opportunity sales,

and interest through August 2006) is $17,639,421. The exact amount of the disallowance would have to be determined at the time of the Decision because interest would continue to accrue until the effective date of the Decision.

Q. What impact would the recommended disallowance have on the Paragraph 19(d) Balancing Account?

A. The disallowed amount should be removed from the Paragraph 19(d) Balancing Account and not be allowed to be recovered from ratepayers.

Q. What should happen to the remaining balance in the Paragraph 19(d) Balancing Account?

A. Staff recommends that APS be allowed to recover the remaining balance through a surcharge.

Q. What amount would be recovered through the surcharge?

A. Removing the disallowed amount would leave $28,464,512 in the Paragraph 19(d) Balancing Account. However, the final amount will depend on how much interest has accrued by the time of the Decision in this case.

Q. What would be the surcharge rate?

A. Staff estimates the surcharge rate to be about $0.001029 per kWh, assuming that the amount to be recovered would be amortized over one year. However, the final surcharge rate will depend on how much interest has accrued by the time of the Decision in this case and on updated forecasts of kWh sales.

Q. What would be the impact of a surcharge on a typical residential customer?

A. Assuming that the final surcharge would be $0.001029 per kWh, the surcharge would add $1.01 to the bill of an E-12 customer with average July 2005 consumption of 981 kWh and $0.84 to the bill of an E-12 customer with median consumption of 818 kWh. Like all PSA rates and surcharges, this proposed surcharge would not apply to customers on E-3 and E-4 rate discount schedules.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. The EPS adjustor rate and caps should be increased to recover an additional $4.25 million for the EPS Credit Purchase Program.
2. The EPS adjustor rate should be set at $0.001392 per kWh with monthly caps per service of $0.56 for residential customers, $20.68 for non-residential customers, and $62.04 for non-residential customers with demands of 3,000 kW or more.
3. The $17,639,421 associated with Palo Verde outages that Staff has recommended to be disallowed should be removed from the Paragraph 19(d) Balancing Account and not be recovered from ratepayers. The exact amount of the disallowance would have to be determined at the time of the Decision because interest would continue to accrue until the effective date of the Decision.
4. APS should be allowed to recover the remaining balance in the Paragraph 19(d) Balancing Account through a surcharge. The surcharge rate would be about $0.001029 per kWh, assuming that the amount to be recovered would be amortized over one year. However, the final surcharge rate will depend on how much interest has accrued by the time of the Decision in this case and on updated forecasts of kWh sales.

Q. Does this conclude your rate design testimony?

A. Yes, it does.

EXHIBIT
5-14
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
BARRY WONG
Commissioner

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 TO AMEND DECISION NO. 67744.	DOCKET NOS. E-01345A-05-0816 E-01345A-05-0826 E-01345A-05-0827

SURREBUTTAL

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEMBER 27, 2006

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NOS. E-01345A-05-0816 ET AL

This surrebuttal testimony addresses new rate schedules proposed by APS in its rebuttal testimony. Although Staff has not found any problems with the proposed rate schedules at this time, Staff is continuing its review and reserves the right to address any concerns at a later date.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony addressing renewable energy for Arizona Public Service ("APS"); in particular, funding for renewable resources, net metering, and green pricing tariffs. That testimony also responded to Commissioner Mayes' July 17, 2006, letter regarding the Renewable Energy Standard and Tariff. I also filed rate design testimony addressing a change in the Environmental Portfolio Standard adjustor rate for Arizona Public Service to recover costs for the EPS Credit Purchase Program, and the establishment of a Power Supply Adjustor surcharge to recover costs associated with nuclear plant outages that have not been found to be imprudent.

Q. What is the subject matter of this surrebuttal testimony?

A. This surrebuttal testimony will address new rate schedules proposed by APS in its rebuttal testimony.

RESPONSE TO NEW RATE SCHEDULES PROPOSED BY APS

Q. Did Staff review the rebuttal testimony of APS witness Mr. Gregory A. DeLizio?

A. Yes.

Q. What did Mr. DeLizio propose in his rebuttal testimony?

A. Among changes to existing and previously proposed rate schedules, Mr. DeLizio proposed three new rate schedules.

Q. Had APS proposed the three new rate schedules previously?

A. No. Staff saw the new rate schedules for the first time in Mr. DeLizio's rebuttal testimony.

Q. What are the three new rate schedules?

A. The proposed rate schedules are Solar-3, E-56, and E-57.

Q. Briefly describe the three rate schedules.

A. Solar-3 would be a Solar Power Pilot Program as an option for residential customers to have their energy needs served from solar power resources constructed by APS.

E-56 would be Partial Requirements Service for general service customers with distributed generation equipment of 100 kW or greater.

E-57 would be Solar Partial Requirements Service for general service customers having solar/photovoltaic generation equipment of greater than 100 kW but less than 1000 kW.

Q. Has Staff analyzed the three rate schedules?

A. Staff began its review of the rate schedules.

Q. Has Staff found any problems with the proposed rate schedules?

A. Not at this time. However, Staff is continuing its review and reserves the right to address any concerns at a later date.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

ARIZONA CORPORATION COMMISSION
STAFF'S EIGHTH SET OF DATA REQUESTS
REGARDING ARIZONA PUBLIC SERVICE COMPANY RATE CASE
DOCKET NO. E-01345A-05-0816
JULY 17, 2006

BEK 8-5 How would the "revenue loss" be calculated?

Response:

APS would incur lost kWh sales for net metering equal to customer's total kWh generation and incur the associated lost revenues consistent with the customer's otherwise applicable rate schedule. The customers' generation kWh output would be estimated by applying a capacity factor or a kWh/kW generation factor to each customer's actual installed kW of generation.

The lost revenues would be derived by applying the average kWh charges in the customer's otherwise applicable rate schedule to the lost kWh. This would include kWh charges for all services (distribution, transmission, generation, system benefits, RES, etc.) The basic service charge and any kW charges would not typically be included in this calculation because the associated revenues are not likely to be reduced with distributed generation, as billed with the net metering rate schedule. This lost revenue would be calculated for each billing month for each participating customer.

The lost revenue would be netted against the associated avoided generation fuel costs that the Company would not incur as the result of the distributed generation. The avoided fuel costs would be calculated by applying the Company's average base fuel costs to the lost kWh. The avoided costs may also include a credit for avoided generation capacity costs, if appropriate.

EXHIBIT
S-15
admitted

Witness: Greg DeLizio

EXHIBIT
S-16
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
BARRY WONG
Commissioner

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 TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816

DIRECT

TESTIMONY

OF

JERRY D. ANDERSON

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 23, 2006

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

Staff's testimony addresses two main topics. First, it addresses Demand-Side Management ("DSM") at the Arizona Public Services Company ("APS" or the "Company") and how DSM programs are funded. Staff recommends that net lost revenue adjustments for DSM programs be disallowed and that the Company should be rewarded for DSM savings through a performance incentive. Staff does not oppose APS' proposal to accrue interest on the Demand-Side Management Adjustment Charge account balance. Secondly, Staff's testimony on APS' System Benefits Charge provides detail and specific recommendations regarding the System Benefits components. Staff recommends that the total of System Benefits should be $49,191,690.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Jerry D. Anderson. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I provide recommendations to the Commission on electric and gas rate filings, purchased power and fuel adjustment matters, Demand-Side Management ("DSM") programs, and other energy-related matters as assigned.

Q. Please describe your educational background and professional experience.

A. I graduated from Western Kentucky University, Bowling Green, Kentucky, receiving a Bachelor of Science degree with double majors in Economics and Business Management. My course of studies included classes in micro-economic price theory, macro-economic theory and business cycles, accounting, management, and data processing. I earned an MBA degree from Xavier University, Cincinnati, Ohio, with an area of concentration in multinational business. After working as a computer programmer for a major oil and refining company, I joined the Rate and Economic Research Department of the Cincinnati Gas & Electric Company (Cinergy/Duke Energy) where I applied my computer skills to rate research, load research, and load forecasting. I was promoted to a succession of more responsible positions over 15 years there and ultimately was named Economist in charge of all electric sales and load forecasting activities. In this position I was responsible for constructing econometric models of the regional economy for the purpose of forecasting electric system peak demands and sales by class of service for a three-state service

territory. Since that time, I have served as a consultant and branch manager of two consulting firms, providing services to such clients as the State of Arizona and the Los Alamos National Laboratories, Los Alamos, New Mexico. More recently, I have held statistical analysis and computer system development positions in the government sector where I was involved with Y2K remediation efforts and interstate unemployment systems. In 2005, I was employed by the ACC as a Public Utilities Analyst. I have participated in various classes on general regulatory and utility issues, including the New Mexico State University's "Basics" class and the Michigan State University's "Camp NARUC" program. I am a member of the National Association for Business Economics.

Q. What is the scope of your testimony in this case?

A. I will address the System Benefits Charge ("SBC") in this rate case and the details of the Arizona Public Service Company ("APS or the "Company") DSM programs, both as a component of the SBC and in the broader overall perspective of APS DSM programs.

Q. Have you reviewed relevant portions of APS' filing in Docket No. E-01345A-0816 submitted by the Company in this case?

A. Yes, I have.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your testimony is organized.

A. My testimony is organized into two main sections. The first section discusses DSM programs at APS and how they are funded. The second section defines System Benefits and identifies each component of the System Benefits Charge in this case. In this section, I will discuss the DSM and low income components of the System Benefits Charge in some detail.

Q. Please summarize your recommendations regarding DSM.

A. Staff recommends that net lost revenue adjustments for DSM programs be disallowed and that the Company should be rewarded for DSM savings through a performance incentive. Staff does not oppose APS accruing interest in the Demand-Side Management Adjustment Charge ("DSMAC") account.

Q. Please summarize your recommendations regarding System Benefits Charge for APS.

A. Staff recommends that the System Benefits Charge be $49,191,690.

DEMAND-SIDE MANAGEMENT

Current APS DSM Programs

Q. What Commission-approved DSM programs did APS conduct during the test year?

A. According to semi-annual DSM reports filed with the Commission, APS conducted the following DSM programs during the test year:

1. Residential Existing Homes Heating, Ventilation, and Air Conditioning ("HVAC") Program (replaced by the Residential HVAC Efficiency Program)
2. Residential New Home Construction Program (replaced by the Residential New Construction Program)
3. Residential Consumer Products Program
4. Energy-Wise Assistance Program (replaced by the Energy-Wise Low Income Weatherization Program)

Q. Do you expect that these DSM programs in operation during the test year will continue in their present form into the future?

A. No. Various Commission decisions during and after the test year approved new DSM programs that will enhance or replace existing APS DSM programs or add to APS' DSM programs. These decisions require a significant expansion of DSM activities at APS. They are a result of Commission approval or interim approval, with modifications, of DSM programs APS proposed in its application for its Demand-Side Management Program Portfolio Plan ("Portfolio Plan") filed with the Commission on July 1, 2005, and its Energy Wise Low Income Weatherization program filed with the Commission on June 6, 2005. Both filings were in compliance with provisions of the Settlement Agreement between APS and the Commission in Decision No. 67744.

Q. Which specific Commission decisions brought about the change and expansion of DSM activities at APS during and after the test year?

A. Decision No. 68064, August 17, 2005, approved the Consumer Products Program. Decision No. 68488, February 23, 2006, granted interim approval for six non-residential DSM programs that were included in APS' Portfolio Plan. The six programs were approved with some modifications and are as follows:

1. Schools Program
2. Non-Residential Existing Facilities Program
3. Non-Residential New Construction and Major Renovation Program
4. Small Non-Residential Program
5. Non-Residential Builder Operator Training Program
6. Non-Residential Energy Information Services Program

Decision No. 68648, April 12, 2006, granted approval for two residential DSM programs that were included in APS' Portfolio Plan. The following two programs were approved with some modifications:

1. Residential New Construction Program
2. Residential HVAC Efficiency Program

Decision No. 68647, April 12, 2006, granted Commission approval of APS' Energy Wise Low Income Weatherization program which was modified and expanded to include a bill assistance component.

Q. Were the DSM programs included in the Portfolio Plan intended to intensify DSM efforts by APS as required in the Settlement Agreement?

A. Yes.

Q. Did some of the DSM programs approved after the test year replace programs that were in effect during the test year?

A. Yes. The Residential HVAC Efficiency Program expanded and replaced the earlier Residential Existing Homes HVAC Program. One of the primary differences in the two programs is that the newer program offers incentives to homeowners for equipment replacement, quality installation, maintenance, and repair by qualified contractors. The Residential New Construction Program expanded and replaced the earlier Residential New Home Construction Program. One of the primary differences between these programs is that the newer program offers incentives for builders to construct energy-efficient new homes. The Energy Wise Low Income Weatherization program is an expansion and modification of the Energy-Wise Assistance Program.

APS DSM Spending

Q. What has been the level of DSM spending during the periods following the Settlement Agreement contained in Decision No. 67744, April 5, 2005?

A. According to semi-annual DSM reports filed by APS, the following levels of DSM spending were recorded:

January – June, 2005	$ 953,501
July – December, 2005	$2,257,280

Q. What level of APS spending on DSM is required by the Settlement Agreement?

A. The Settlement Agreement requires at least $16 million to be spent on DSM per year.

Q. Is the $16 million per year spending requirement only for the years 2005 – 2007 or does it continue beyond 2007?

A. The $16 million annual spending requirement included in the Settlement Agreement remains in effect until the Commission acts to change or cancel it.

Q. Did APS meet the spending requirement imposed by the Settlement Agreement in 2005?

A. No. Because the Settlement Agreement was effective in April 2005, APS was obligated to spend only $10 million in 2005. However, this level of spending was not achieved in 2005 since most of the programs were not approved until 2006.

Cost Recovery for DSM Expenditures

Q. How does APS recover its costs for DSM programs?

A. The funding structure for DSM was established in the Settlement Agreement. The funding comes in both base rates and through an adjustor. According to the Settlement

Agreement, $10 million of DSM funding is included in base rates. The balance, a minimum of $6 million per year, is to be collected by an adjustor mechanism referred to as the DSMAC. A provision of the Settlement Agreement also states that if APS does not spend at least $30 million on approved DSM from 2005 through 2007, the unspent amount of the $30 million base rate allowance ($10 million per year) would be credited to the DSMAC account balance.

Q. How does the DSMAC work?

A. As approved in Decision No. 67744, the DSMAC is an adjustment mechanism consisting of an account where the costs for pre-approved DSM programs in excess of those prescribed to be in base rates are recovered. For example, DSM costs in excess of the $10 million to be included in base rates each year would be recorded in the DSMAC account. Such costs are to be recorded for each program by APS as the costs are incurred. By January 31 of each year, APS is to file data with Staff needed to set the per kWh DSMAC rate. APS is to document the costs placed in each DSM adjustment subaccount during the previous year and the revenue received from ratepayers through the per kWh charge during the previous year. The per kWh charge for the next year is to be calculated by dividing the account balance by the number of kWh used by customers in the previous year. General Service customers who are billed on a demand rate are to pay a per kW charge instead of a per kWh charge. To calculate the per kW charge, the account balance is to be first allocated to the General Service class based upon the number of kWh consumed by that class. General Service customers that are not demand billed are to pay the DSMAC adjustor rate on a per kWh basis. The remainder of the account balance allocated to the General Service class is to be divided by that kW billing determinant for the demand-billed customers in that class to determine the per kW DSM adjustor charge. The DSMAC adjustor rate is to be reset in this manner each year on March 1.

Q. What charges can be included in the DSMAC account?

A. Eligible DSM-related items in excess of the $10 million included in base rates may be included in the DSMAC account. This includes Commission-approved energy efficiency DSM programs, low income bill assistance, and a performance incentive.

Q. How are residential customers billed?

A. For residential customers, the DSMAC adjustment, as a charge per kWh, is combined with the Environmental Portfolio Standard ("EPS") adjustment and included on all customer bills as a separate line item labeled "Environmental Benefits Surcharge."

Q. Should the DSMAC account accrue interest?

A. Currently, the DSMAC account does not accrue interest. In the testimony of APS witness David J. Rumolo, pages 15-16, APS has proposed the inclusion of interest earnings on the unrecovered DSMAC account balance. Staff does not oppose the accrual of interest in the DSMAC account. Staff does not oppose APS' proposal that the balance in the DSMAC account should accrue the interest using the one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release H-15 or its successor publication.

Q. What is Staff's position on APS' proposal for a proforma adjustment to test year data to recover net lost revenue resulting from DSM programs?

A. Staff recommends disallowance of APS' proposed $4,907,000 proforma adjustment for net lost revenue resulting from DSM programs.

Q. What is Staff's rationale for disallowance of the net lost revenue adjustment proposed by APS?

A. Staff's position is that APS should be compensated for its efforts to make DSM programs available and for the savings achieved by successful DSM programs through a performance incentive. A performance incentive and an adjustment for net lost revenues are two separate approaches to compensating the utility. Staff sees these techniques as mutually exclusive where you would allow one of the approaches or the other, but not both.

Q. Does the Settlement Agreement provide for the recovery of a performance incentive resulting from successful DSM programs?

A. Yes, it does.

Q. What are some of the advantages of the performance incentive?

A. The performance incentive is appealing because it is based upon a share of the actual net benefits accruing from approved successful DSM programs. As such, it is an incentive that rewards a utility's performance in conducting successful DSM programs. If money were spent on a DSM program that did not result in energy efficiency savings, there would be no performance incentive paid.

Q. Did APS propose a performance incentive in its Portfolio Plan of DSM programs?

A. Yes, it did. APS proposed a 90 percent/10 percent split between customers and the company respectively of the total net benefits accruing from approved DSM programs. It further proposed that the incentive be capped at 10 percent of the total amount of DSM spending, inclusive of the program incentive, and be reported in the semi-annual DSM reports filed with the Commission pursuant to Decision No. 67744. The Company further

proposed that the incentive be determined for each reporting period based on the savings and net benefits reported for that semi-annual period.

Q. Does Staff concur with APS' proposal for a performance incentive?

A. Yes, conceptually it does. Staff recommends that the performance incentive be set at 10 percent of the net benefits from the energy efficiency achieved through approved DSM programs and that the performance incentive be capped at 10 percent of total DSM spending inclusive of the performance incentive.

Q. Would APS be guaranteed to collect $1.6 million in performance incentives (10 percent of the $16 million expected to be spent each year on DSM programs?

A. No. The $1.6 million would be the maximum performance incentive APS could collect annually based on DSM spending of $16 million per year. The actual performance incentive would be based upon actual energy efficiency savings achieved as a result of successful DSM programs.

Q. Should the net benefits be estimated from engineering calculations or should they be based upon savings factors measured by the Measurement, Evaluation, and Research contractor (MER)?

A. Net benefits of a DSM measure are defined as benefits minus costs associated with that measure. The benefits should be based upon actual measured savings resulting from before and after MER measurements where possible and where practical. For most prescriptive measures, the savings could be calculated by averaging a sample of actual measured usage for both standard and upgraded equipment for each energy-efficiency measure. For some prescriptive measures, such as replacement of a standard light bulb with a compact fluorescent light bulb, an engineering calculation may be more practical

and would be acceptable. For large custom efficiency measures which are more unique, the savings should be based upon actual MER measurements both before the measure implementation and afterwards. The type of measurement and whether actual measurement is necessary or whether an engineering calculation would be acceptable will vary with the type of DSM measure.

Q. Should the averages of actual measured usage, for both standard and upgraded equipment, used to calculate savings for each measure be periodically updated?

A. Yes. The averages should be recalculated by the MER from usage samples for each prescriptive measure based on new measurements from the field no less frequently than every two years.

Q. Could engineering estimates be used to determine kW and kWh savings at lower cost than a monitoring program?

A. Engineering data can provide some guidance on savings, but data on actual experience, taking into account customer behavior and field performance of the measure, is essential. An example of customer behavior influencing kW and kWh savings is when the customer lowers a thermostat because the new air conditioner is more efficient and costs less to operate. Actual experience may be far different than engineering data would suggest. Another reason for using actual field measurement averages is that baseline usage as well as energy-efficient equipment usage is constantly moving toward increased energy efficiency over time. While it may be less expensive to rely on engineering estimates, such estimates could be providing kW and kWh savings numbers that are incorrect or not representative of Arizona's unique climate characteristics.

Q. Should the performance incentive accrue to the utility at the time the DSM expenditures are made and the measures are installed or over the life of the measures concurrent with the actual customer realization of the benefits?

A. Where it may be more theoretically correct to reward the utility as actual DSM savings accrue over the life of each measure installed, it is not practical to require the utility to wait up to 20 years to recover its performance incentive. Furthermore, the recordkeeping required to pay out a portion of savings each year over the life of each measure could be excessively costly and difficult for Staff to monitor. Staff recommends that APS should share in the benefits of the DSM measures as they are placed into service and expenditures are incurred. APS' Portfolio Plan application suggests that the performance incentive should be determined for each reporting period based on the savings and net benefits reported for that period. APS currently reports this information in each semi-annual DSM report, January – June and July – December. Staff recommends that APS include their request for a performance incentive payment in each semi-annual DSM report. The benefits during a measure's life minus the costs during the year the measure was installed equals the net benefits of that measure for that period.

Q. How should the DSM-related demand and energy savings be priced for comparison with the DSM cost in the calculation of net benefits?

A. APS' avoided cost should be used as the basis to assign a dollar value to DSM demand and energy savings.

Q. What specific calculations or methodology should be used to determine kW and kWh savings and to apply APS avoided costs to those savings to determine the net benefit of the DSM measures undertaken?

A. APS has not proposed a specific calculation or methodology. Determining the net benefits of DSM programs can be a technical and complex undertaking. Staff recommends APS submit its specific calculation and/or methodology for determining the net benefits of DSM measures and the performance incentive itself in its rebuttal testimony in this docket.

Q. Does Staff have nay additional recommendations regarding DSM?

A. Yes. Staff recommends that APS provide Staff with backup workpapers and input data substantiating numbers for net benefits and performance incentives included in its semi-annual DSM report. The backup information should be in sufficient detail to allow Staff to reproduce the numbers reported for net benefits and the performance incentive in the semi-annual DSM report.

Q. What information should be provided for Staff review?

A. The information provided to Staff should include the net benefit calculations and performance incentive dollar amount calculations for the total amount of the performance incentive reported. The calculations should be disaggregated such that the dollar amount of net benefits and performance incentive for each grouping of like individual measures within each DSM program are identifiable and, when added together, equal the total net benefits and performance incentive dollars requested for that DSM program. Major inputs should be provided along with documentation sufficient that Staff could reproduce the calculations. Inputs should include the numbers of like measures, the measure life, the avoided cost factors, discount rates used in present value calculations, kW and kWh

savings and how they were derived, coincidence factors, actual cost data, line losses, and any other data required to duplicate the calculations.

Q. When should the information be provided to Staff?

A. APS should provide the information to Staff at the same time as APS files its semi-annual DSM reports.

SYSTEM BENEFITS CHARGE

Background on System Benefits Charges

Q. What are System Benefits?

A. A.A.C. R14-2-1601(41) defines System Benefits as "Commission-approved utility low income, demand-side management, Consumer Education, environmental, renewables, long-term public benefit research and development, nuclear fuel disposal and nuclear power plant decommissioning programs, and other programs that may be approved by the Commission from time to time."

Q. What is the System Benefits Charge?

A. A.A.C. R14-2-1608 requires each utility distribution company to file for Commission review nonbypassable rates or related mechanisms to recover the applicable pro-rata costs of System Benefits from all consumers located in the utility distribution company's service area. Utility distribution companies are to file for review of the System Benefit Charge ("SBC") at least every three years.

Q. Why were System Benefits Charges established?

A. The concept of System Benefits developed as a mechanism to preserve and promote the establishment and maintenance of renewables, DSM, and programs for low income

customers. Investment in these programs and research into the reduction of long-term dollar and environmental costs through energy conservation and the development of renewable resources are an important function of public utility companies. When competition began to develop in the electric utility industry, however, there was concern that utilities would be forced through competition to concentrate on short-term results and lose its focus on important long-term objectives to promote conservation, the use of renewables, and some nuclear plant-related expenses. The System Benefits Charge was established to provide a mechanism that would ensure utilities could retain their focus on desirable long-term objectives without suffering an undue economic setback or competitive disadvantage. An important characteristic of the System Benefits Charge is that customers should continue to pay for system benefits even if they choose a different generation supplier; i.e. it is nonbypassable. The System Benefits Charge essentially re-classifies certain costs that are currently in rates to assure that important public benefits are not at risk. The charge is shown as a line item on customer bills.

System Benefits Components

Q. What are the components of APS' System Benefits Charge?

A. The System Benefit components and the amounts requested by APS and recommended by Staff are summarized in the following table:

System Benefits Components	APS Proposed	Staff Recommended
Demand-Side Management Programs	$10,000,000	$10,000,000
Low Income Programs (E-3/E-4 Rates)	$4,222,330	$4,372,330
Renewables	$6,000,000	$6,000,000
Palo Verde Power Plant Decommissioning	$18,901,703	$18,901,703
Independent Spent Fuel Storage Installation (ISFSI)	$10,177,404	$9,917,657
Total System Benefits	$49,301,437	$49,191,690

Q. Which portion of DSM expenses falls within the System Benefits Charge?

A. Only that portion of DSM expenses that are funded within base rates is included in the System Benefits Charge. The portion of DSM expenses that are funded through the DSMAC is outside the System Benefits Charge.

Q. What amount is Staff recommending to be included for DSM in the System Benefits Charge?

A. Staff recommends including $10,000,000 for DSM, the amount approved by Decision No. 67744.

Q. What amount is Staff recommending to be included for low income programs (E-3/E-4 Rates) in the System Benefits Charge?

A. Staff recommends including $4,372,330 for low income programs. This amount is $150,000 more than APS proposed. APS included $4,222,330 which represents the amount of discounts received by customers in the test year adjusted for the change in discount rates approved by Decision No. 67744. In response to Data Request JDA 9-7,

APS indicated that there were also administrative and marketing expenses for both the E3 and E4 programs, including $87,847 in the test year plus a proforma adjustment of $62,153 to bring the level to $150,000 as approved by Decision No. 67744. APS states that these administrative and marketing expenses are for direct program promotion and marketing expenses only and do not include APS labor and overhead costs to administer the programs. Staff believes that it is appropriate to include the $150,000 in System Benefits.

Q. Which portion of renewables expenses falls within the System Benefits Charge?

A. Only that portion of renewable expenses that are funded within base rates is included in the System Benefits Charge. The portion of renewables expenses that are funded through the Environmental Portfolio Surcharge Adjustor is outside the System Benefits Charge.

Q. What amount is Staff recommending to be included for renewables in the System Benefits Charge?

A. Staff recommends including $6,000,000 in the System Benefits Charge for renewables. This amount is discussed in the Direct Testimony of Staff witness Barbara Keene.

Q. What amount is Staff recommending to be included for Palo Verde Power Plant decommissioning in the System Benefits Charge?

A. Staff recommends including $18,901,703 for Palo Verde Power Plant decommissioning, as proposed by APS.

Q. What amount is Staff recommending to be included for ISFSI in the System Benefits Charge?

A. Staff recommends including $9,917,657 for ISFSI. APS had included $10,177,404 for ISFSI. The proposed reduction of $259,747 is discussed in the testimony of Staff witness James R. Dittmer.

Total System Benefits

Q. What amount is Staff recommending for the total System Benefits Charge?

A. Staff recommends $49,191,690 for the total System Benefits Charge.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT
S-17
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
BARRY WONG
Commissioner

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 TO AMEND DECISION NO. 67744.	)	DOCKET NOS. E-01345A-05-0816 E-01345A-05-0826 E-01345A-05-0827

SURREBUTTAL

TESTIMONY

OF

JERRY D. ANDERSON

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

September 27, 2006

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NOS. E-01345A-05-0816 ET AL

Staff adds clarification that any under-spending for DSM below the $30 million in base rates during the period 2005 through 2007 will result in the amount of the under-spending being applied as a credit to the DSM adjustor account. Staff also comments on SWEEP's proposal to implement an Energy Efficiency Standard ("EES") in which Staff agrees with APS that the EES is aggressive and possibly premature, but believes it is useful for planning for future energy efficiency. Staff also sets a time limitation on the use of measured energy savings values from sources other than the Measurement, Evaluation, and Research ("MER") contractor in the calculation of the DSM Performance Incentive and sets a date when actual measured savings must be used in those calculations. Staff also contends that energy savings resulting from DSM measures are not known and measurable and adds that argument to its position that APS' proposed revenue adjustment for DSM-related reduced revenues should be disallowed.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Jerry D. Anderson. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony in this rate case regarding the System Benefits Charge ("SBC") and the details of the Arizona Public Service Company ("APS" or the "Company") Demand-Side Management ("DSM") programs and how they are funded.

Q. **Have you reviewed relevant portions of APS' and other parties' rebuttal testimony in this case?**

A. Yes, I have.

PURPOSE OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this case?

A. This surrebuttal testimony will clarify Staff's position on some issues related to APS DSM programs and introduce an additional argument that reduced revenues resulting from DSM measures during the period 2005 through 2007 are not known and measurable.

SUMMARY OF SURREBUTTAL TESTIMONY

Q. Please summarize your surrebuttal testimony.

A. Staff adds clarification that any under-spending for DSM below the $30 million in base rates during the period 2005 through 2007 will result in the amount of the under-spending being applied as a credit to the DSM adjustor account. Staff also comments on SWEEP's

proposal to implement an Energy Efficiency Standard ("EES") in which Staff agrees with APS that the EES is aggressive and possibly premature, but believes it is useful for planning for future energy efficiency. Staff also sets a time limitation on the use of measured energy savings metrics from sources other than the Measurement, Evaluation, and Research ("MER") contractor in the calculation of the DSM Performance Incentive and sets a date when actual measured savings must be used in these calculations. Staff also contends that energy savings resulting from DSM measures are not known and measurable and adds that argument to its position that APS' proposed revenue adjustment for DSM-related reduced revenues should be disallowed.

Q. Do you have any modifications to make to your direct testimony?

A. No, I do not.

DEMAND-SIDE MANAGEMENT

Q. Is Staff in agreement with APS witness Teresa A. Orlick's rebuttal testimony with regard to how under-spending of DSM dollars in the period 2005 through 2007 is handled?

A. Staff believes Ms. Orlick's explanation requires some clarification. Ms. Orlick's rebuttal testimony indicates that APS does not believe that the $48 million required by Decision No. 67744 to be spent on DSM programs during the period 2005 through 2007 will be achieved. She also indicated that any under-spending of the $48 million will be carried over and spent in subsequent years in addition to the $16 million required for each of those years. Decision No. 67744 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 is to be credited to the account balance of the Demand-Side Management Adjustment Clause ("DSMAC") account. If APS desires to spend in

excess of the required $16 million in any subsequent year, it may do so and recover all spending for approved DSM-related items incurred over $10 million each year through the DSMAC. The $16 million DSM spending requirement is an annual minimum spending requirement.

Q. Is Staff in agreement with APS staff witness Teresa A. Orlick's rebuttal testimony in which she expresses concerns about SWEEP's Energy Efficiency Standard ("EES")?

A. Staff agrees that the EES proposed for APS by SWEEP witness Jeff Schlegal is very aggressive and perhaps somewhat premature. APS is still in the early implementation phases of a broad range of new DSM programs proposed in the APS Demand-Side Management Portfolio Plan ("Portfolio Plan") and approved in 2005 and 2006. Mr. Schlegal's proposal, however, has merit in that planning for future energy efficiency expansion is important. Staff would disagree with Ms. Orlick's testimony that a DSM spending goal is always more appropriate than a DSM savings goal as proposed by SWEEP. Although APS currently has a DSM spending goal, there could be merits in using a savings goal in the future, as it is the energy efficiency savings that are the desired end result. Ms. Orlick is correct that APS DSM incentive levels are generally limited by the Commission to 50 to 75 percent of incremental cost. Staff believes that it is important for the customer to "buy in" to energy savings by investing some of the customer's own money for efficiency measures. Staff currently is not convinced that incentives of 100 percent of incremental cost are required to achieve higher levels of energy savings.

Q. Did APS agree with Staff's proposals in regard to a DSM Performance Incentive?

A. Yes, generally Staff and APS are in agreement regarding the Performance Incentive. Ms. Orlick's testimony suggests that the program-filed savings metrics be utilized in the calculation of the performance incentive until such time as MER contractor results are

available. Staff understands that MER results may not yet be available. However, Staff recommends that APS should use the most recent and regionally similar energy savings data available instead of the program-filed savings numbers from 2005. In addition, APS should incorporate results from the Baseline Study into its calculations. Nevertheless, Staff believes that a time limit should be placed upon the use of energy use measurements from other regions. Staff recommends that APS use measured savings obtained from APS customers by the MER contractor beginning no later than July 1, 2007, such that the year-end DSM Semi-annual Report for the period July 1, 2007, through December 31, 2007, and the Performance Incentive calculations contained therein, are based on these measured savings supplied by the MER. Staff's objective is for APS to use savings metrics that most accurately reflect patterns in APS' service territory. Because of Arizona's unique desert climate, metrics obtained from other states may not accurately reflect savings in Arizona.

DSM-RELATED REDUCED REVENUE PRO FORMA ADJUSTMENT

Q. Do you agree with the rebuttal testimony of APS staff witness Peter M. Ewen (page 6) that lists DSM energy savings related to the Company's DSM spending obligations as a factor already known for 2007?

A. No. I do not. Staff believes that the DSM spending for the remainder of the Portfolio Plan period, 2005 through 2007, is very much in question. The energy savings resulting from that spending is even more difficult to quantify with certainty.

Q. Is it Staff's position, then, that revenue reductions attributable to DSM measures for the remainder of 2006 and 2007 are not known and measurable?

A. Yes, that is Staff's position.

Q. What levels of DSM spending has APS recorded to date relative to their $16 million per year ($48 million for 2005 through 2007) obligation for the period 2005 through 2007?

A. According to DSM Semi-Annual Reports APS filed with the Commission, the following levels of DSM spending have been recorded:

January – June 2005	$ 953,501
July – December 2005	$2,257,280
January – June 2006	$2,686,449

Q. How does the actual level of DSM spending compare to the spending obligations required by Decision No. 67744?

A. Because Decision No. 67744 was issued on April 5, 2005, the spending obligation for 2005 was reduced to $10 million. However, the 2005 through 2007 spending obligation remains at $48 million. The $6 million reduction in 2005 was intended to facilitate a ramp-up of the programs, thus the latter years need to exceed the $16 million annual obligation to make up for the $6 million reduction in 2005. The distribution of the spending over $16 million for 2006 and 2007 is flexible, so for illustrative purposes I will assume the $6 million from 2005 will be made up in 2007.

Year	Obligation	Spending	Variance
2005	$10,000,000	$3,210,781	-68%
2006	$16,000,000	$2,686,449 (6-months only)	
2007	$22,000,000	(unknown at this time)	
TOTAL	$48,000,000		

At this time, we have actual spending results from the DSM Semi-Annual Reports for the first year and one-half of the 2005 through 2007 period. During this 1.5-year span,

representing half of the 3-year 2005 through 2007 period, $5.9 million of the $48 million obligation has been spent.

Q. Is it likely that the $48 million spending requirement for the period 2005 through 2007 will be achieved?

A. Staff believes the $48 million DSM Portfolio Plan spending goal for 2005 through 2007 may not be achieved; however, it is unknown at this time. Staff acknowledges that one of the reasons that spending is lagging is that, with the exception of the Consumer Products Program, the programs were not approved by the Commission until 2006. Staff is also aware that this three-year period is a ramping-up period for the Portfolio Plan DSM programs, and that much of the early efforts will not result in actual savings until a later time. Staff fully expects that DSM spending during July through December 2006 and during 2007 will be significantly higher than that experienced to date. The extent of spending during this period is unknown at this time; however, it appears very unlikely that APS' $48 million, three-year Portfolio Plan spending goal will be achieved.

Q. Does APS expect that the $48 million DSM Portfolio Plan spending goal for 2005 through 2007 will be achieved?

A. No. Ms. Orlick's rebuttal testimony on page 2 states that "Due to the delayed approval of the programs and the steep ramp-up from a level of $1 million of DSM spending per year prior to Decision 67744 to the current level of $16 million per year, APS does not believe that $48 million will be spent by year end 2007."

Q. Would you conclude that the level of DSM spending for 2005 through 2007 is not known at this time?

A. Yes, I would.

Q. Are there additional factors besides DSM spending that affect DSM savings and ultimately revenue reductions resulting from successful DSM programs?

A. Yes there are. Actual DSM kW and kWh savings are currently being estimated from engineering calculations and savings factors from national databases which are primarily measured in states other than Arizona. APS has only within the past three months hired its own MER contractor to measure savings actually achieved in the APS service territory as a result of successful APS' DSM measures. The use of actual measured savings in APS' service territory will provide more accurate demand and energy savings; however, APS has indicated such actual measured savings will not be available until some time in the future. The conversion of demand and energy savings into revenue reductions is a calculation that is also an estimation, adding even more uncertainty to the actual revenue reduction attributable to DSM programs.

Q. Would you conclude that APS's proposed pro forma revenue adjustment should be disallowed on the basis that the revenue reduction resulting from DSM is not known and measurable?

A. Yes, I would.

Q. Are there other reasons why Staff is recommending disallowance of APS' proposed pro forma adjustment to compensate for revenue shortfalls resulting from DSM savings?

A. Yes. I outlined in my direct testimony and in responses to discovery that Staff has proposed a Performance Incentive for APS to reward it for successful DSM programs instead of an adjustment for DSM-caused revenue reductions. Allowing the Company both a pro forma DSM lost revenue adjustment and a Performance Incentive would be duplicative. If DSM-induced lost revenue were possible to measure definitively, the pro

forma would compensate APS for every dollar of DSM revenue that was saved through DSM measures. If a DSM Performance Incentive were also allowed, APS would then be compensated over the amount of the DSM revenue reductions. Staff feels that APS should share in the DSM savings with its customers who adopt DSM measures through a Performance Incentive, but it should not be compensated twice for the same effort.

Q. Is Staff confusing an adjustment to base rates in a general rate case for a known and measurable condition with a year-by-year net lost revenue approach as proposed in APS witness Peter M. Ewen's rebuttal testimony on page 10?

A. No. Staff explained in its response to APS-Staff-4-4 that APS's proposed adjustment for reduced revenues owing to successful DSM programs is a one-time pro forma adjustment to the test year. Staff believes such an adjustment should not be allowed for the reasons stated herein and that a Performance Incentive similar to that proposed by APS in its Portfolio Plan should be adopted instead.

Q. Is staff witness Peter M. Ewen's testimony regarding the funding of APS's DSM programs through base rates and a DSM adjustment mechanism accurate?

A. No. It appears there is a typographical or transposition error in his rebuttal testimony at page 11. The Company was ordered by the Commission in Decision No. 67744 to spend $10 million recovered in base rates and at least $6 million recovered through the DSM adjustment mechanism.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT
S-18
admitted

Staff Exhibit No. ____

BEFORE THE ARIZONA CORPORATION COMMISSION

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, and to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Develop Such Return, and To Amend Decision No. 67744	)	Docket No. E-01345A-05-0816

DIRECT TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF
THE ARIZONA CORPORATION COMMISSION,
UTILITIES DIVISION STAFF

Phoenix, Arizona
August 18, 2006

DIRECT TESTIMONY OF RALPH C. SMITH
EXECUTIVE SUMMARY

My testimony addresses the following issues:

- The Company's proposed depreciation rates.

My findings and recommendations for each of these areas are as follows:

- The depreciation rates proposed by APS presented in Mr. White's Attachments REW-1 and REW-2 should be adopted for use in this case. The depreciation rates proposed by APS were developed in a manner that is consistent with the Commission's rules for depreciation rates. My review of the details provided in Mr. White's Attachments REW-1 and REW-2 and other information indicates that those new rates proposed by APS are consistent with a "technical update" approach to the depreciation rates that the Commission approved in Decision 67744. The net change in percentage terms resulting from APS's technical update in composite terms is fairly small, an increase of 0.06 percentage points for APS plant and a decrease of 0.20 percentage points for plant that APS acquired from PWEC.

- Each of the new depreciation rates proposed by APS should be clearly broken out between (1) a service life rate and (2) a net salvage rate, similar to the rates shown in Appendix A to the Commission's Decision No. 67744. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

DIRECT TESTIMONY OF RALPH C. SMITH
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ATTACHMENTS:

RCS-1, Background and Qualifications
RCS-2, Commission Rule R14-2-102, Treatment of depreciation
RCS-3, Appendix A from Commission Decision No. 67744 showing APS's current depreciation rates by component.

I. INTRODUCTION

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. I am also a Certified Financial Planner™

1 professional and a Certified Rate of Return Analyst (CRRA). Since 1981, I
2 have been a member of the Michigan Association of Certified Public
3 Accountants. I am also a member of the Michigan Bar Association and the
4 Society of Utility and Regulatory Financial Analysts (SURFA). I have also
5 been a member of the American Bar Association (ABA), and the ABA
6 sections on Public Utility Law and Taxation.

7 **Q. Please summarize your professional experience.**

8 A. Subsequent to graduation from the University of Michigan, and after a short
9 period of installing a computerized accounting system for a Southfield,
10 Michigan realty management firm, I accepted a position as an auditor with
11 the predecessor CPA firm to Larkin & Associates in July 1979. Before
12 becoming involved in utility regulation where the majority of my time for the
13 past 26 years has been spent, I performed audit, accounting, and tax work
14 for a wide variety of businesses that were clients of the firm.

15 During my service in the regulatory section of our firm, I have been
16 involved in rate cases and other regulatory matters concerning numerous
17 electric, gas, telephone, water, and sewer utility companies. My present
18 work consists primarily of analyzing rate case and regulatory filings of public
19 utility companies before various regulatory commissions, and, where
20 appropriate, preparing testimony and schedules relating to the issues for
21 presentation before these regulatory agencies.

22 I have performed work in the field of utility regulation on behalf of
23 industry, state attorney generals, consumer groups, municipalities, and

public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, Washington D.C., and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. Have you previously submitted testimony and/or testified before other state regulatory commissions on issues involving the review of electric utility depreciation expense?

A. Yes. Most recently I testified before the Delaware Public Service Commission on such issues in Docket No. 05-304, a Delmarva Power and Light Company rate case.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified before the Commission previously on a number of occasions. Most recently, I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS" or "Company").

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the depreciation rates proposed by APS in the current rate case.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 and RCS-3 contain copies of selected documents that are referenced in my testimony.

II. DISCUSSION OF ISSUES

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed depreciation rates and follows through on issues raised by the Staff concerning depreciation rates in the last APS rate case.

Q. Please briefly describe the information you reviewed in preparation for your testimony.

A. The information I reviewed included the Commission's rules regarding depreciation, testimony and exhibits from the prior APS rate case, Docket No. E-03145A-03-0437, APS's application and testimony in the current case, APS's responses to data requests of Staff and other parties, Excel files supporting APS witness Ronald White's "2005 Technical Update" of APS's

depreciation rates, information provided to me by Staff, and other publicly available information.

A. The Company's Proposed Depreciation Rates

Q. Please provide some background for the request that APS has made in the current proceeding as it relates to the Company's depreciation rate proposals.

A. In APS's last rate case, Docket No. E-01345A-03-0437, APS presented a depreciation study prepared by Mr. John Wiedmayer of Gannett Fleming, Inc. The study contained recommended remaining life depreciation accrual rates as of December 31, 2002, and was attached to APS witness Laura Rockenberger's direct testimony in that proceeding as Attachment LLR-4. A witness on behalf of the Staff, Michael Majoros, raised a number of significant issues concerning the depreciation rates that had been proposed by APS. A settlement was ultimately reached among APS, Staff and other parties in Docket No. E-01345A-03-0437. That settlement provided as follows concerning Depreciation issues:

> "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 set 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 purposes of this proceeding, the Parties agree that SFAS 143 shall not be adopted for ratemaking purposes."

Attachment RCS-3 reproduces for ease of reference Appendix A from Decision No. 61744. This contains the detailed depreciation rates by account that the parties agreed to in their stipulation in APS' last rate case.

Q. What did Commission Order 61744 state with respect to the depreciation rates?

A. Commission Order 61744, at page 19, stated as follows concerning 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."

Q. What Commission rules address the treatment of depreciation?

A. The Commission's rules at R14-02-102 address the treatment of depreciation. A copy of these rules are presented, for ease of reference, in Attachment RCS-2. The current version of the rules appear to have been adopted effective April 9, 1992. This pre-dates the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" which has resulted in revisions for financial reporting purposes, among other things, of the presentation of cost of removal information. I discuss SFAS No. 143 in more detail subsequently in my testimony.

Q. Did APS file a new depreciation study in the current rate case?

A. No. Instead of performing a full depreciation study in which asset lives and net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, APS has presented a "2005 Technical Update." As described on page 7 of Dr. Ronald White's direct testimony on behalf of APS:

> "a technical update generally retains the parameters currently used or proposed by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates due to the passage of time. A technical update, therefore, is intended to align

depreciation rates with the accounting year the rates will become effective."

Q. Please discuss the Company's proposed depreciation rates and how they were derived.

A. The new depreciation rates proposed by APS are summarized in Company witness Dr. White's testimony and are shown in detail in his exhibits, Attachments REW-1 (for APS plant) and REW-2 (for PWEC units acquired by APS). As noted above, APS' new depreciation rates were not the result of a complete depreciation study, but resulted from a "2005 technical update." The Company's proposed rates were developed using a depreciation system composed of the straight-line method, broad group procedure and remaining life technique. APS has developed its proposed depreciation rates for production facilities by unit and by type of plant in service at each unit. This appears consistent with the development of depreciation rates for APS that was accepted by the Commission in APS' last rate case, Docket No. E-01345A-03-0437.

Q. What impact do the new depreciation rates proposed by APS have?

A. As summarized on page 10 of Dr. White's testimony, based on December 31, 2004 plant investment, the new depreciation rates proposed by APS for APS plant <u>increase</u> depreciation expense by $5,222,168 (from $221,616,212 at present rates to $226,838,380 at APS' proposed rates). For the Pinnacle West Energy Company ("PWEC") units acquired by APS, the new

depreciation rates decrease depreciation expense by $1,980,690 (from $28,789,932 at present rates to $26,809,242 at APS' proposed rates). The combined impact for APS plant and the PWEC units acquired by APS is a net increase of approximately $3.241 million in depreciation expense on December 31, 2004 plant.

On a composite basis[1], the Company's proposed new rates for APS plant produce an increase of 0.06 percentage points, from the current composite rate of 2.89% to a composite at new rates of 2.95%. For the PWEC units, the new depreciation rates proposed by APS produce a composite rate of 2.67%, which is 0.20 percentage points less that the equivalent present composite rate of 2.87%.

Q. Did APS add plant since the last case that was not considered in the development of its depreciation rates in that proceeding?

A. Yes. The following power plants were transferred from PWEC to APS on July 29, 2005: Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3. Of these transferred assets, West Phoenix Unit 5 was not considered in the establishment of depreciation rates in Docket No. E-01345A-03-0437. As described in the Company's response to data request STF-11-5:

> "The depreciation rates used for each PWEC unit before the units were transferred to APS were approved as part of Decision No.

[1] APS does not apply its depreciations on a composite basis; this information is for comparative purposes only.

67744. (See Appendix A to that Decision, pages 20-21.) Note that West Phoenix CC5 was under construction during the 2003 rate case. Therefore, there are no rates for that unit in Decision No. 67744. The rates used for West Phoenix CC5 were based on the service life statistic and net salvage rates approved for Redhawk."

Redhawk Units 1 and 2 are a matching pair of 530-megawatt combined cycle plants near the Palo Verde switchyard. West Phoenix Unit 5 is also a 530-megawatt combined cycle unit.

Q. Before discussing specific issues associated with APS' proposed depreciation rates, could you please provide your understanding of some basic depreciation terminology?

A. Yes, of course.

Q. What is depreciation?

A. The Commission's rules at R14-2-102(A)(3) define "depreciation" as "an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life."

Q. What is net salvage?

A. The Commission's rules at R14-2-102(A)(5) define "net salvage" as "the salvage value of property less the cost of removal."

Q. What is "salvage value"?

A. The Commission's rules at R14-2-102(A)(5) define "salvage value" as:

"the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; of if retained, the amount at

which the material recoverable is chargeable to materials and supplies, or other appropriate accounts."

Q. What is the "cost of removal"?

A. The Commission's rules at R14-2-102(A)(5) define the "cost of removal" as "the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto."

Q. What is depreciation expense?

A. Depreciation expense is a charge to operating expense to reflect the recovery of depreciable utility plant. Depreciation rates are applied to a utility's depreciable utility plant to determine the amount of depreciation expense. Public utility depreciation expense is typically straight-line over the service life which results in an equal share of the cost of assets being assigned or allocated to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant and equipment is in service. [2]

Q. What is depreciable utility plant?

A. Public utilities record their plant investment activity in the individual plant accounts set-forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Plant additions, retirements and balances are maintained by plant account. An annual addition is the original

[2] National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices, August, 1996. ("NARUC Depreciation Manual"), p. 321. Also, Commission Rule R14-2-102, which

cost of plant added to the account during the year. A retirement is recorded in the plant account by removing the original cost of a prior addition when such plant is removed from service. The plant balance is what is left at the end of an accounting period after accounting for additions and retirements.

Q. How is the annual depreciation expense calculated?

A. Annual depreciation expense, called an accrual, is calculated by applying a depreciation rate to plant balances.

Q. Is the depreciation accrual a cash expense?

A. No. Depreciation is considered a non-cash expense.

Q. Please explain the distinction between a cash and non-cash expense.

A. Depreciation expense is considered a non-cash accrual. This contrasts with payroll expense, for example, which involves the current outlay of cash. Depreciation expense does not involve a specific payment during the test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and is simultaneously recorded on the balance sheet in the accumulated depreciation account; which is shown as an offset to plant in service. The following accounting entries illustrate the difference:

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defines "service life" as "the period between the date an asset is first devoted to public service and the date of its retirement from service."

Account	Description	Amount Dr. (Cr.)
403	Depreciation Expense	$ 1,000
108	Accumulated Depreciation	$ (1,000)
	To record depreciation	

various	Payroll Expense	$ 1,000
131	Cash	$ (1,000)
	To record payroll expense	

Q. What is the Accumulated Depreciation account?

A. Accumulated Depreciation, Account 108 in the USOA, is a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. From a regulatory perspective, Accumulated Depreciation can be considered a measure of the depreciation recovered from ratepayers. Commission Rule R14-2-102 defines "accumulated depreciation" as "the sum of the annual provision for depreciation from the time that the asset is first devoted to public service."

Q. How does depreciation expense impact a utility's revenue requirement?

A. Annual depreciation expense is a cost that is included in a public utility's revenue requirement. Because public utilities tend to be capital intensive, depreciation expense can be a significant component of the utility's revenue requirement.

Q. What is the objective of depreciation expense?

A. From a regulatory perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original

cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances. Additionally, many state regulatory commissions, including the ACC, have allowed utilities to recover through the commission-authorized depreciation rates, the utility's estimated future cost of removal, which is part of the net salvage component of the depreciation rates.

Q. Please illustrate how depreciation rates are developed.

A. The following calculation shows a straight-line whole-life depreciation rate assuming a 10-year average service life and a $1 million plant investment, and the whole life method. Each year the 10% depreciation rate would be applied to plant in service to produce an annual depreciation expense and an entry to accumulated depreciation:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: 100% / 10 Years = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
1	$ 100,000	$ (100,000)
2	$ 100,000	$ (200,000)
3	$ 100,000	$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 1,000,000	

Q. What happens at the end of an asset's life under this scenario?

A. All things equal, at the end of 10 years, the plant balance will be 100% (or $1 million), and the accumulated depreciation balance will also be 100% (also

$1 million). This equality is important to understanding issues relating to the cost of removal/negative net salvage.

Q. What is negative net salvage?

A. Negative net salvage is the difference between any salvage value and the cost of removal of the asset after completion of its service life. If the cost of removal exceeds the salvage amount, this produces negative net salvage. In this testimony I will use the terms negative net salvage and net cost of removal interchangeably. The ratemaking treatment of negative net salvage was raised as an issue by a Staff witness (Mr. Majoros) in the last APS rate case, Docket No. E-01345A-03-0437. Negative net salvage can have a significant impact on a utility's depreciation rates and revenue requirement.

Q. What happens if estimated future negative net salvage is included in the calculation?

A. Assume a negative 55 percent (-55%) net salvage ratio. The above whole-life example with a 55% value for negative net salvage is as follows:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [100% - (-55%)] / 10 Years = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
1	$ 100,000	$ (100,000)	$ 55,000	$ (55,000)
2	$ 100,000	$ (200,000)	$ 55,000	$ (110,000)
3	$ 100,000	$ (300,000)	$ 55,000	$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 1,000,000		$ 550,000	

In this example, negative net salvage increases the resulting whole -life depreciation rate from 10% to 15.5%, i.e., by 55%. This increase results from the inclusion of estimated future net cost of removal, including estimated future inflation.

Q. Please explain the "FAS 143 Regulatory Liability" column in the above example.

A. Because the Company has no current legal obligation to pay the estimated future inflated cost of removal (negative net salvage) amounts (i.e., has no asset retirement obligation), the excess amounts recovered through depreciation rates are accumulated in a regulatory liability account for financial reporting purposes, pursuant to Statement of Financial Accounting Standards No. 143. (SFAS 143) I will explain certain provisions in SFAS 143 that require such treatment in more detail later in my testimony.

Q. Why does negative net salvage increase the depreciation rate?

A. It increases the depreciation rate because negative salvage is, in effect, added to the original cost of the plant. Instead of 100% (which represents the original cost of assets), the numerator becomes 155%. This is equivalent to capitalizing or adding the estimated cost of removal to the original cost of the asset. In the above example, instead of recovering the original plant cost of $1 million, the depreciation rates would recover $1.55 million.

Q. What happens at the end of life under this scenario?

A. The plant balance will be 100% but the sum of the accumulated depreciation balance and the regulatory liability account will be 155%. Consequently,

unlike the "zero net salvage scenario" shown above, when negative net salvage is included in a depreciation rate, there will not be an equality of plant and reserve at the end of an asset's life because the Company will have charged more depreciation than it paid for the original cost of the asset. Under these circumstances, equality will only be achieved if the Company actually spends additional money at the end of the asset's life.

Q. Is the Company required to pre-collect from ratepayers estimated future amounts of money that it might spend at the end of plant useful life?

A. While for some of its assets APS has no current legal liability to spend money for estimated future cost of removal, the Commission rules at R14-2-102(B)(3) require that: "The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systematic manner over the estimated service life of the plant." As discussed above, the Commission's rules define "net salvage" to include the cost of removal. Consequently, I conclude that the Commission's rules require cost of removal to be included in the utility's depreciation rates.

Q. If the Company does incur an obligation at the end of an asset's service life that requires spending money for removal, can the Company take the money out of accumulated depreciation?

A. No. Accumulated Depreciation is an unfunded account. Even though the Company collected money from ratepayers for future removal cost that had

been included in past depreciation rates, it will have already spent that money on whatever it chose in the past: salaries, dividends, etc.

Q. Please explain the concept of remaining life depreciation.

A. The remaining life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining life rather that the whole life of the asset.

Q. What happens when accumulated depreciation is incorporated into the numerator of the basic depreciation calculation?

A. If the 10-year asset is 3 years old, its remaining life would be 7 years (10 – 3 = 7). The accumulated depreciation account would be 30% of the original cost because the 10% depreciation rate would have been applied for three years (3 x 10% = 30%). The remaining life depreciation rate would then be 10%, calculated as follows:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: [100% - 30%] / [10 - 3 Years] = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
3		$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 700,000	

Under the example with the assumed 55% negative net salvage, and a 7-year remaining life, the results would be a 15.5% depreciation rate, as shown below:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [(100% - (-55%)) - (3 x 15.5%)] / [10 - 3 Years] = 15.5% Per Year
Depreciation Rate: [(108.5%)] / [7 Years] = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
3		$ (300,000)		$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 700,000		$ 385,000	

Q. Why would the whole-life depreciation rate in the example with negative net salvage and the remaining life depreciation rate in the negative net salvage example both be 15.5 percent?

A. In these examples, the remaining life depreciation rate and the whole-life depreciation rates are the same (15.5 percent) because I have assumed that the accumulated depreciation account is in balance. In other words, based on a continuation of the fundamental parameters, i.e., the 10-year service life and the negative 55% net salvage ratio, exactly the right amount of depreciation has been charged and collected in the past.

Q. What would happen if either of these fundamental parameters were to change?

A. If either the service life or net salvage parameter changes during the life of the plant, the accumulated depreciation account will be out of balance, and

the remaining life rate will be either higher or lower than whole-life rate depending on the direction of the imbalance. That is because the Company will have collected either too much depreciation or not enough depreciation in the past, given the current estimates of lives or future net salvage. The difference between the actual amount recovered, as included in the book depreciation reserve, and a theoretical estimate of what should be in the book reserve, is called a "reserve imbalance." The remaining life technique is often used to deal with such reserve imbalances.

Q. Since the last revision to the Commission's rules regarding the treatment of depreciation, has a significant accounting pronouncement been issued?

A. Yes. As noted above, it appears that the Commission's rules concerning the treatment of depreciation were last revised and became effective April 9, 1992. Since that date, generally accepted accounting principles (GAAP), specifically SFAS 143, highlight the amounts associated with estimated future cost of removal for which no current legal obligation exists and require that they be reported as Regulatory Liabilities for financial reporting purposes. A regulatory liability can be viewed as an amount owed to ratepayers.

Q. What is SFAS 143?

A. The Financial Accounting Standards Board ("FASB") is a standards-setting body for the public accounting profession. In June 2001, the FASB promulgated Statement of Financial Accounting Standards No. 143 (FAS

143). This pronouncement addresses the appropriate accounting for long-lived assets. It is effective for all fiscal years beginning after June 15, 2002. However, earlier application was encouraged. Pursuant to SFAS 143, all companies, both unregulated (e.g., Walmart) and regulated (e.g., APS) must review all of their long-lived assets to determine whether or not they have actual legal obligations to remove retired assets. For some plant and equipment, companies have a legal obligation to remove the asset at the end of the service life. These legal obligations for future removal are called asset retirement obligations ("AROs"). For other assets, no such obligation exists.

If a company does have an ARO, the fair value of the future retirement cost, which is determined using net present value techniques, is considered to be part of the original cost of the asset. That ARO is therefore capitalized (included in the original cost) and depreciated over the life of the asset. In essence, if a Company incurs a legal liability to spend money to remove an asset at the end of its life, that liability is part of the cost of the asset.

In contrast, if a company does <u>not</u> have such legal obligations, the future cost of removal will <u>not</u> be capitalized as part of the asset cost and will <u>not</u> be included in depreciation expense. Only the initial cost of the asset (which does not include estimated inflated future cost of removal for which no current liability exists), will be depreciated.

At the end of the asset's life, for assets without AROs, the accumulated depreciation account will equal the plant balance. In other words, under SFAS 143, there is symmetry between assets with and without

AROs. In both cases, the accumulated depreciation will equal the original cost of the asset at the end of its life.

Q. How are AROs measured?

A. AROs are measured at their net present value, not their inflated future value.

Q How are AROs recorded for accounting purposes?

A. As stated above, AROs are capitalized as a cost of the related asset and simultaneously recorded as a liability for those companies with a legal obligation to remove a retired asset. To illustrate, assuming an ARO of $500, the $500 would be debited (i.e., added) to plant and simultaneously credited (i.e., added) to the regulatory liability account. Each year, as the liability increases due to inflation, the increase is charged to accretion expense and credited to the liability, but the asset value remains the same. In other words, just as the original cost of the asset does not increase, neither does the capitalized asset retirement cost.

Q. What happens if a company does not have an asset retirement obligation pursuant to SFAS 143?

A. If a company does not have such obligations, the estimated future inflated cost of removal is not considered as a cost of the asset, and therefore it will not be included in the company's depreciation expense on its general purpose financial statements. SFAS 143, therefore, unbundles net salvage from depreciation rates. It does this in two ways: (1) by incorporating the net present value of an ARO in the cost of the asset, or (2) by excluding non-AROs from the depreciation rate calculations.

Q. What is the accounting impact of SFAS 143 for electric utilities?

A. Under Generally Accepted Accounting Principles ("GAAP"), electric utilities are required to review all of their assets to determine if they have any AROs. If a utility has any AROs, they are capitalized. Paragraph B73 of SFAS 143 provides an exception for regulated utilities, which allows them to continue to incorporate net salvage factors ("non-legal AROs") in depreciation rates even if they do not have AROs. Utilities are also required to determine the amount of any prior cost of removal collections relating to non- AROs that is now included in their accumulated depreciation accounts, and reclassify these and any such future charges as a regulatory liability in their financial statements. In other words, even with the paragraph B73 exception, SFAS 143 provides transparency through reporting disclosure requirements.

Q. What is the impact of SFAS 143 on electric regulatory accounting?

A. FERC addressed SFAS 143 in Docket RM02-7-000 which resulted in Order No. 631. FERC Order 631 essentially adopts SFAS 143 and integrates it into the Uniform System of Accounts. Utilities are required to review their long - lived assets to determine if they have any AROs. Where utilities do not have AROs, any charges for such amounts must be separately identified. FERC Order 631 defines cost of removal allowances for which there is no legal asset retirement obligation, as "non-legal retirement obligations." Past and future "non- legal AROs" must be specifically identified and accounted for separately in the depreciation studies, depreciation expense and the accumulated depreciation account. In Order 631, FERC maintains the

1 transparency resulting from the "separation principle" for non-legal AROs that
2 was established in paragraph B73 of SFAS 143. Paragraph 38 of Order 631
3 explains FERC's new requirements for non-legal AROs:

4 "Instead, we will require jurisdictional entities to maintain separate
5 subsidiary records for cost of removal for non-legal retirement
6 obligations that are included as specific identifiable allowances
7 recorded in accumulated depreciation in order to separately identify
8 such information to facilitate external reporting and for regulatory
9 analysis, and rate setting purposes. Therefore, the Commission is
10 amending the instructions of accounts 108 and 110 in Parts 101, 201
11 and account 31, Accrued depreciation - Carrier property, in Part 352
12 to require jurisdictional entities to maintain separate subsidiary
13 records for the purpose of identifying the amount of specific
14 allowances collected in rates for non-legal retirement obligations
15 included in the depreciation accruals."

16 **Q. Does FERC provide any additional insight as to the interpretation of**
17 **these new rules?**

18 A. Yes, at paragraph 39 of the order, FERC states:

19 "Jurisdictional entities must identify and quantify in separate
20 subsidiary records the amounts, if any, of previous and current
21 accumulated removal costs for other than legal retirement obligations
22 recorded as part of the depreciation accrual in accounts 108 and 110
23 for public utilities and licensees, account 108 for natural gas

1 companies, and account 31 for oil pipeline companies. If jurisdictional
2 entities do not have the required records to separately identify such
3 prior accruals for specific identifiable allowances collected in rates for
4 non-legal asset retirement obligations recorded in accumulated
5 depreciation, the Commission will require that the jurisdictional entities
6 separately identify and quantify prospectively the amount of current
7 accruals for specific allowances collected in rates for non-legal
8 retirement obligations."

9 **Q. Does FERC make any policy calls concerning the appropriate treatment**
10 **of the disposition of prior and future collections contained in these**
11 **separate allowances?**

12 A. No. As indicated at paragraph 64 of the Order, FERC declined to make such
13 calls on a policy basis. Rather, FERC will resolve the appropriate treatment
14 of the dispositions of prior and future collections on a case-by-case basis.

15 **Q. Does FERC's Order require anything new or more with respect to its**
16 **requirement for detailed depreciation studies?**

17 A. No. At paragraph 65 of the Order, FERC states that:

18 "... this rule requires nothing new and nothing more with respect to the
19 requirement for a detailed study. Complex depreciation and negative
20 salvage studies are routinely filed or otherwise made available for
21 review in rate proceedings. When utilities perform depreciation
22 studies, a certain amount of detail is expected. It is incumbent upon

1 the utility to provide sufficient detail to support depreciation rates, cost
2 of removal, and salvage estimates in rates."
3 Additionally, footnote 45 states:
4 "When an electric utility files for a change in its jurisdictional rates, the
5 Commission requires detailed studies in support of changes in annual
6 depreciation rates if they are different from those supporting the
7 utility's prior approved jurisdictional rate."
8 Thus, FERC recognizes distinctions between legal and non-legal AROs just
9 as SFAS 143 recognizes those distinctions. On a going-forward basis,
10 jurisdictional entities must be prepared to specifically identify and justify any
11 non-legal AROs that they propose to include in rates.
12 **Q. Has APS implemented SFAS 143?**
13 A. Yes. The Company implemented SFAS 143 on January 1, 2003.
14 Footnote 11 from APS's 2003 SEC Form 10-K states with respect to the
15 initial adoption of this accounting, that on January 1, 2003 the Company
16 adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." In its
17 2003 SEC Form 10-K, APS states further that:
18 "In accordance with SFAS No. 71, we will continue to accrue for
19 removal costs for our regulated assets, even if there is no legal
20 obligation for removal. At December 31, 2003, regulatory liabilities
21 shown on our Balance Sheets included approximately $480 million of
22 estimated future removal costs that are not considered legal
23 obligations."

Moreover, consistent with adopting this accounting principle for financial reporting purposes, APS "reclassified prior year removal costs of approximately $557 million previously included in accumulated depreciation to the liability for asset retirements and removals in our Balance Sheets. In 2003, we reclassified the portion of this liability for which no legal obligation for removal costs exists to a regulatory liability."

When initially adopting SFAS 143, companies such as APS, reclassified for financial statement reporting purposes their accumulated cost of removal for which there is no current legal obligation for removal, from Accumulated Depreciation and reported this as a Regulatory Liability.

As described on page 78 of the Company's 2005 Securities and Exchange Commission ("SEC") Form 10-K:

> "APS records a regulatory liability for the asset retirement obligations related to its regulated assets. This regulatory liability represents the difference between the amount that has been recovered in regulated rates and the amount calculated under SFAS No. 143 'Accounting for Asset Obligations,' as interpreted by FIN 47. APS believes it can recover in regulated rates the costs calculated in accordance with SFAS No. 143."

Under "Regulatory Liabilities" on its 2005 SEC Form 10-K, APS reported a "regulatory liability related to asset retirement obligations" of $86 million and $101 million as of December 31, 2004 and 2005, respectively. Under "Regulatory Liabilities" on its 2005 SEC Form 10-K, APS also reported a

regulatory liability of $376 million and $385 million as of December 31, 2004 and 2005, respectively, related to removal costs, with this note: "In accordance with SFAS No. 71, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal."

Q. Are the "costs of removal" that were reclassified as a regulatory liability for financial reporting purposes the result of APS's past depreciation rates?

A. Essentially, yes. APS's past depreciation rates have included negative net salvage. This has resulted in APS pre-collecting from ratepayers estimated future costs of removal for non-legal AROs, which under SFAS 143, have been reclassified for financial reporting purposes as a regulatory liability.

Plant and equipment are retired from service at the end of their useful life. Sometimes the retired plant and equipment may be physically removed and can be resold for value. This is called gross salvage. The cost of removal net of the value received for the salvage constitutes net salvage. In more technical terms, gross salvage is the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property. Cost of removal is the cost incurred in connection with the retirement from service and the disposition of depreciable plant. As discussed above, net salvage is the difference between gross salvage and cost of removal.

Q. Are net salvage ratios included in the Company's depreciation rate calculations?

A. Yes. Substantial negative net salvage ratios are included in several of APS's depreciation rates. The inclusion of negative future net salvage ratios in APS's proposed depreciation rates result in depreciation rates that are significantly higher in many instances than if no cost of removal had been included. As noted above, the inclusion of net salvage in depreciation rates appears to be consistent with past practices of the utility and Commission, and appears to be required by Commission rule R14-2-102(B)(3).

Q. Do APS's proposed depreciation rates include estimated future removal costs?

A. Yes. As noted above, APS's proposed depreciation rates include estimated future removal costs, including estimated future inflation. APS has done this by including negative net salvage ratios in the development of depreciation rates for many, but not all, of its depreciable plant assets.

Q. Where does APS develop its estimated future cost of removal that are included in its proposed depreciation rates?

A. These are developed in Mr. White's Attachments REW-1 and REW-2, on Statement D (average net salvage), Statement E (future net salvage and Statement F (dismantlement costs) of those attachments.

Q. Did you request APS to provide its <u>actual</u> cost of removal and net salvage information by plant account?

A. Yes. This was requested in data request STF-11-30 for years 2000 through 2005.

Q. Did APS provide that requested information plant account?

A. No. APS' response to data request STF-11-30 stated: "APS did not record cost of removal and salvage at the plant account level for the periods requested." APS did provide total amounts by year.

Q. How much actual negative net salvage has the Company been experiencing in total?

A. The following table summarizes the annual cost of removal and salvage information that was provided by APS in response to data request STF-11-30:

Annual Net Salvage
Per APS' Response to Data Request STF-11-30

Year	Annual Cost of Removal	Annual Gross Salvage	Annual Net Salvage
2000	$ 4,796,643	$ (10,694,073)	$ (5,897,430)
2001	$ 14,136,598	$ (7,230,051)	$ 6,906,547
2002	$ 11,046,897	$ (9,119,972)	$ 1,926,925
2003	$ 14,270,117	$ (4,956,898)	$ 9,313,219
2004	$ 8,697,802	$ (10,318,654)	$ (1,620,852)
2005	$ 15,910,845	$ (10,444,823)	$ 5,466,022
Averages:			
2000-04	$ 10,589,611	$ (8,463,930)	$ 2,125,682
2001-05	$ 12,812,452	$ (8,414,080)	$ 4,398,372

Q. Have you made a comparison of how much APS's proposed depreciation rates would collect annually for estimated future cost of removal with the Company's recent actual cost of removal?

A. No. During the course of my analysis, I started to make such a comparison, but concluded that it was not necessary for purposes of this case because the Commission's rules at R14-2-102 require net salvage to be included in the development of the utility's depreciation rates. Since I am not recommending an adjustment to reflect an alternative treatment of cost of

removal in this case, the comparative calculation related to quantifying such an adjustment was not pursued as it would have been if an adjustment to the Company's approach was being recommended.

Q. Has APS's approach to including net salvage in depreciation rates been widely used in the utility industry?

A. Yes. Many regulated utilities have used this approach. It is even addressed in the NARUC's 1996 Public Utilities Depreciation Practices Manual as a recommended approach. On the other hand, the same NARUC Manual at page 157 also states:

> "Some commissions have abandoned the above procedure [gross salvage and cost of removal reflected in depreciation rates] and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred."

Q. In your opinion, is there a reasonable alternative to the approach used by APS?

A. Yes. Instead of incorporating estimated future cost of removal along with estimated future inflation into depreciation rates, providing a normalized level of removal cost as a current-period expense is a reasonable alternative for ratemaking purposes, in my opinion.

Q. Does the NARUC Manual indicate that some utility commissions are using this alternative approach?

A. Yes. The NARUC Manual at page 158 states that:

> It is frequently the case that net salvage for a class of property is negative, that is, cost of removal exceeds gross salvage. This circumstance has increasingly become dominant over the past 20 to 30 years; in some cases negative net salvage even exceeds the original cost of plant. Today few utility plant categories experience positive net salvage; this means that most depreciation rates must be designed to recover more than the original cost of plant. The predominance of this circumstance is another reason why some utility commissions have switched to current period accounting for gross salvage and, particularly, cost of removal.

Q. Could APS's approach result in accumulated depreciation exceeding the original cost of plant in service?

A. Yes. One of the mechanical problems with APS's approach is that it can result in a depreciation reserve actually exceeding the gross plant balance. That is because the depreciation rates proposed by APS for distribution plant include estimated future cost of removal, and therefore produce higher depreciation rates than are necessary to fully depreciate the original cost of the plant. Therefore, at the end of its life, the accumulated depreciation account exceeds the plant account balance. Referring back to the hypothetical illustration that I presented earlier, with a 55% negative net salvage assumption, at the end of the 10-year assumed useful life, the utility has recorded $1.55 million in depreciation on a depreciable asset of $1 million. During the plant's depreciable life, the utility had no asset retirement obligation, but it would have collected an extra $550,000.

Q. How should the allowance for cost of removal be calculated?

A. Because the Commission's rules at R14-2-102 in their current form clearly require the inclusion of net salvage in the development of the utility's depreciation rates, and this is what APS has done, I am not in this proceeding recommending an alternative. Were it not for those rules, I believe there is substantial merit in the alternative recommended by the witness for Staff in the prior APS rate case, which would provide for a normalized allowance for cost of removal based on the average of the most recent five years worth of actual net salvage activity. Essentially, the cost of removal is treated just as any other normalized operating expense.

Q. Are you aware of whether other regulatory commissions use that alternative approach for utility recovery of cost of removal?

A. Yes. A five-year average net salvage allowance approach has been used for many years by the Pennsylvania Public Utility Commission. In recent years, some other state regulatory commissions have used similar approaches that exclude estimated future cost of removal from the development of depreciation rates, and provide an allowance for the cost of removal based on an average of a utility's actual incurred cost.

Q. What are the advantages of that approach?

A. The five-year rolling average for recovery of cost of removal provides a reasonable method for addressing this controversial aspect of depreciation. APS's proposed development of depreciation rates essentially treats estimated future costs of removal (including estimated future inflation) as a

current period expense, even when there is no current legal obligation to incur such cost. In contrast with APS's approach, a normalized expense allowance approach better conforms with the generally accepted accounting principles articulated in SFAS 143 by not treating estimated inflated future removal costs as if they were a current obligation and a current expense. Additional advantages offered by the normalized expense allowance approach include that it is simple, straight-forward and easy to implement, provides an opportunity for the Company to recover a normalized allowance for cost of removal based on recent actual cost, and avoids charging current customers for estimated future inflation. However, the Commission's rules at R14-2-102 in their present state would appear to preclude this alternative for purposes of this case.

Rule R14-2-102 is a rule of general applicability to electric utilities in the state of Arizona. Because I believe there is no compelling reason to treat cost of removal (where there is no current obligation to incur such cost) differently from other normalized operating expenses, I recommend that the Commission consider amending Rule R14-2-102 to allow treatment of cost of removal in the manner recommended by Staff's consultant in the prior APS rate case.

Q. Should the depreciation rates proposed by APS be adopted for use in this case?

A. Yes. The depreciation rates proposed by APS presented in Mr. White's Attachments REW-1 and REW-2 should be adopted for use in this case. The

depreciation rates proposed by APS were developed in a manner that is consistent with the Commission's rules for depreciation rates. My review of the details provided in Mr. White's Attachments REW-1 and REW-2 and other information indicates that those new rates proposed by APS are consistent with a "technical update" approach to the depreciation rates that the Commission approved in Decision 67744. As noted above in my testimony, the net change in percentage terms resulting from APS's technical update in composite terms is fairly small, an increase of 0.06 percentage points for APS plant and a decrease of 0.20 percentage points for plant that APS acquired from PWEC.

Q. Do you have any other recommendations concerning the depreciation rates proposed by APS?

A. Yes. Each of the new depreciation rates proposed by APS should be clearly broken out between (1) a service life rate and (2) a net salvage rate, similar to the rates shown in Appendix A to the Commission's Decision No. 67744. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, PSC staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)

U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)

R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016,	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
Phase I	
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)

R14-2-102. Treatment of depreciation

A. The following definitions shall apply in this Section unless the context otherwise requires:

1. "Accumulated depreciation" means the summation of the annual provision for depreciation from the time that the asset is first devoted to public service.
2. "Cost of removal" means the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto.
3. "Depreciation" means an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life.
4. "Depreciation rate" means the percentage rate applied to the original cost of an asset to yield the annual provision for depreciation.
5. "Net salvage" means the salvage value of property retired less the cost of removal.
6. "Original cost" means the cost of property at the time it was first devoted to public service.
7. "Property retired" means assets which have been removed, sold, abandoned, destroyed, or which for any cause have been withdrawn from service and books of account.
8. "Salvage value" means the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; or if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts.
9. "Service life" means the period between the date an asset is first devoted to public service and the date of its retirement from service.

B. All public service corporations shall maintain adequate accounts and records related to depreciation practices, subject to the following:

1. Annual depreciation accruals shall be recorded.
2. A separate reserve for each account or functional account shall be maintained.
3. The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systemic manner over the estimated service life of such plant.
4. Public service corporations having less than $250,000 in annual revenue shall not be required to maintain depreciation records by separate accounts but shall make annual composite accruals to accumulated depreciation for total depreciable plant.

C. Requests for depreciation rate changes and methods for estimating depreciation rates shall be as follows:

1. If a public service corporation seeks a change in its depreciation rates, it shall submit a request for such as part of a rate application in accordance with the requirements of R14-2-103.
2. A public service corporation may propose any reasonable method for estimating service lives, salvage values, and cost of removal. The method shall be fully described in a request to change depreciation rates.
3. Data and analyses supporting the change shall be submitted, including engineering data and assessment of the impact and appropriateness of the change for ratemaking purposes.
4. Changed depreciation rates shall not become effective until the Commission authorizes such changes.

D. Upon the motion of any party or upon its own motion, the Commission may determine that good cause exists for granting a waiver from one or more of the requirements of this Section.

Historical Note

Former Section R14-2-102 repealed, former Section R14-2-127 renumbered as Section R14-2-102 without change effective March 2, 1982 (Supp. 82-2). Forward to the rule corrected as filed April 13, 1973 (Supp. 89-1). Section R14-2-102 repealed, new Section adopted effective April 9, 1992 (Supp. 92-2).

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-DistributionLines	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)		Proposed Rates for 2004	(1995) Current Rates
Class	Description		
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	Comrnerical Vehides, 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. 18-32Ton, Line Construction with Aerial	5.33%	5.33%
17	4-Wheel Dr. 10-15 Ton, Truck	6.92%	6.92%
19	Trucks, 18-32Ton, 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.

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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. 2 112 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%
78	4-Wheel Or. 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	04 Caterpillar (Small)	7.50%	7.50%
33	07 Caterpillar (Medium)	7.50%	7.60%
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%	489%
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 Kate (B)	Net Salvage Rate (C)
OTHER PRODUCTION				
FERC 341	Structures and Improvements	2.08%	1.98%	0.10%
FERC 342	Fuel Holder;, 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 (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)
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	20,385,831	22.8	894,107	3.29%
Ocotillo Units 1-2	06-2020	75 - S1.5	(20)	3,787,972	2,084,288	2,461,276	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)	462,587	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)	26,431,661	17,605,653	14,112,384	13.4	1,053,182	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)	100,448,985	60,203,487	60,335,291	22.9	2,634,729	2.62%
Cholla Common	06-2035	48 - L2	(20)	22,626,051	11,326,185	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	121,282,892	12.7	9,546,259	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	1,144,083	4.69%
Total Account 312				800,031,516	462,014,636	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)	39,628,197	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	10,299,684	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%

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

	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	28.8	955,676	2.26%
	Cholla Unit 3	06-2035	60 - R2.5	(20)	29,917,208	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	5,039,776	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	74,156	2.79%
	Total Account 315				134,807,415	80,088,776	81,680,122		3,642,426	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)	4,848,431	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	06-2036	40 - R2	(20)	7,096,069	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	3,463,659	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 Reclamation	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
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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)
	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	121,216,478	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)	25,449,873	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	51,570,898	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	45,858,840	20.8	2,204,658	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)	29,871,405	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	16,214,350	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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	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	126,016	126,016	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				2,081,066	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	4,146	842	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	468,971	885,980	14.4	61,528	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 Cyc	06-2031	80 - S1	(5)	6,706,722	2,438,622	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	1,019,600	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 Cyc	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	2,858,228	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	181,867	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	74,265	1.80%	

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	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 Cyc	06-2031	37 - R3	(2)	81,920,222	11,983,119	71,575,507	26.2	2,731,690	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	28,393,951	81,746,531		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 Cyc	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 Cyc	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.

TRANSMISSION PLANT										
352	Structures and Improvements	50 - R4	(5)	27,618,299	12,484,018	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	6,536,127	1.52%
353.5	Station Equipment - SCE 500 I			7,747,262	7,349,363	397,919		251,787	3.25% (a)
354	Towers and Fixtures	60 - R3	(35)	83,464,531	46,097,366	56,579,751	38.3	1,738,376	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)	16,551,254	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		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 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	17,968,638	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)	53,919,851	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		88 - O1	(5)	425,723,118	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		38 - 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	91,088,515	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		28 - 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	3,663,126	26,539,871	45.0	589,775	2.33%	
373	Street Lighting and Signal Syst		35 - R2	(20)	57,165,737	22,718,125	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)	96,687,435	24,085,116	87,082,434	30.7	2,836,581	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	4,416,633	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					8,082,832,804	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			
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	314,612
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				1,833,193					
322	Reactor Plant Equipment				9,870,223					
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				246,938					
	TOTAL OTHER PROPERTY NOT STUDIED				229,866,377	120,727,768				
	TOTAL DEPRECIABLE PLANT IN SERVICE				8,369,701,276	3,348,108,323				
	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 (6) 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) = (5)*100/(100+(-4))	Annual Accrual Service Life Rate (12)=(11)/(5)	Annual Accrual Net Salvage Amount (13) = (5) *(-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)	2,144,759	1,841,738	732,008	14.0	52,266	2.44%	643,672	2.03%	$8,714	0.41%
Cholla Unit 2	06-2033	75 - S1.5	(20)	5,022,178	2,101,615	3,925,000	29.0	135,345	2.69%	112,797	2.25%	22,557	0.45%
Cholla Unit 3	06-2035	75 - S1.5	(20)	9,663,277	5,184,966	6,314,966	29.8	211,203	2.20%	178,002	1.84%	36,200	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)	16,972,927	10,628,079	8,539,433	13.5	642,063	4.02%	535,052	3.35%	107,010	0.67%
Four Corners Units 4-5	06-2031	75 - S1.5	(20)	9,195,685	5,124,992	6,909,710	26.6	220,512	2.40%	183,760	2.00%	36,752	0.40%
Four Corners Common	06-2031	75 - S1.5	(20)	3,946,871	2,227,706	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	12,187,389	20,365,631	22.6	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	2,084,284	2,461,278	17.1	143,834	3.80%	119,945	3.17%	23,889	0.63%
Saguaro Units 1-2	06-2014	75 - S1.5	(20)	2,446,832	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)	482,587	452,608	102,472	13.1	7,822	1.69%	6,518	1.41%	1,304	0.28%
Total Account 311				115,950,068	63,151,681	75,958,416		3,282,764	2.84%	2,743,962	2.37%	548,792	0.47%
312 Boiler Plant Equipment													
Cholla Unit 1	06-2017	45 - L2	(20)	28,431,681	17,605,653	14,112,364	13.4	1,053,182	3.86%	877,635	3.32%	175,527	0.66%
Cholla Unit 2	06-2033	45 - L2	(20)	140,612,492	86,692,363	82,042,627	22.0	3,728,210	2.65%	3,107,675	2.21%	621,535	0.44%
Cholla Unit 3	06-2035	45 - L2	(20)	100,448,965	60,203,487	60,335,291	22.8	2,634,729	2.62%	2,195,607	2.19%	439,121	0.44%
Cholla Common	06-2035	45 - 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	45 - L2	(20)	197,139,757	116,304,816	121,262,882	12.7	9,548,259	4.84%	7,956,883	4.04%	1,591,377	0.81%
Four Corners Units 4-5	06-2031	45 - L2	(20)	111,591,873	64,306,071	69,804,177	22.1	3,149,510	2.82%	2,624,592	2.35%	524,918	0.47%
Four Corners Common	06-2031	45 - L2	(20)	3,290,391	2,152,160	1,796,306	22.8	79,785	2.39%	65,655	2.00%	13,131	0.40%
Navajo Units 1-3	06-2026	45 - L2	(20)	149,350,243	69,950,378	109,289,914	20.6	5,304,385	3.55%	4,420,304	2.96%	884,061	0.59%
Ocotillo Units 1-2	06-2020	45 - L2	(20)	24,152,351	17,905,383	11,077,439	15.2	726,778	3.02%	607,318	2.51%	121,463	0.50%
Saguaro Units 1-2	06-2014	45 - L2	(20)	24,387,712	16,555,160	12,699,094	11.1	1,144,083	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	6,041,181	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	15,516,951	18,743,318	27.6	681,575	2.39%	567,979	1.99%	113,596	0.40%
Cholla Unit 3	06-2035	65 - R2	(20)	39,826,197	18,658,280	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	16,568,225	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	7,066,302	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)	1,726,184	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)	24,367,110	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	7,183,863	16.8	427,612	2.76%	356,343	2.30%	71,269	0.46%
Saguaro Units 1-2	06-2014	65 - R2	(20)	18,258,898	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	112,700,859	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)	4,758,908	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	25,070,831	25,612,111	26.8	955,678	2.26%	796,398	1.89%	159,279	0.38%
Cholla Unit 3	06-2035	60 - R2.5	(20)	29,917,206	16,287,820	19,832,827	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	10,096,339	13.2	765,026	4.65%	637,521	3.90%	127,504	0.78%
Four Corners Units 4-5	06-2031	60 - R2.5	(20)	9,183,206	6,039,778	5,960,069	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%

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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)
	Saguaro Units 1-2	06-2014	60 - R2.5	(20)	2,654,581	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	80,088,778	61,580,122		3,842,428	2.70%	3,035,354	2.25%	807,071	0.45%
316	Miscellaneous Power Plant Equipment													
	Cholla Unit 1	06-2017	40 - R2	(20)	2,315,189	1,180,333	1,555,694	13.5	117,596	5.08%	98,080	4.24%	19,616	0.85%
	Cholla Unit 2	06-2033	40 - R2	(20)	4,848,431	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	2,976,036	23.6	125,044	3.02%	104,203	2.52%	20,841	0.50%
	Cholla Common	06-2035	40 - R2	(20)	7,099,069	2,439,747	6,075,536	25.6	235,456	3.32%	196,238	2.77%	39,248	0.55%
	Four Corners Units 1-3	06-2019	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	3,453,859	6,278,210	23.2	270,528	3.33%	225,438	2.77%	45,088	0.55%
	Navajo Units 1-3	06-2028	40 - R2	(20)	11,805,259	5,246,830	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	18.2	194,557	5.24%	162,131	4.37%	32,426	0.87%
	Saguaro Units 1-2	06-2014	40 - R2	(20)	3,191,024	1,346,385	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)	452,884	359,601	183,641	12.2	15,053	3.32%	12,544	2.77%	2,509	0.55%
	Total Account 316				53,324,730	22,313,112	41,876,564		2,209,705	4.14%	1,841,421	3.45%	368,284	0.69%
	TOTAL STEAM PRODUCTION PLANT				1,292,132,201	746,269,083	818,288,858		42,781,850		35,634,959		7,146,992	
	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	88,416,270	36,858,061	49,558,209	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	169,591,077	53,133,223	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	74,471,088	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	38,318,906	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)	358,545,213	153,818,828	213,119,289	20.6	10,345,697	2.88%	10,142,742	2.82%	202,955	0.06%
	Palo Verde Unit 2	12-2025	70 - R1	(2)	178,362,235	72,582,559	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	7,175	118,503	23.0	5,157	4.18%	5,056	4.10%	101	0.08%
	Palo Verde Common	03-2027	70 - R1	(2)	28,440,873	9,583,436	17,395,434	22.8	769,709	2.91%	754,617	2.65%	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)	30,722,375	27,569,149	8,376,030	3.0	2,792,010	9.09%	2,366,333	7.77%	405,677	1.32%
	Palo Verde Unit 2	12-2003	Square	(17)	16,870,063	15,868,635	2,899,327	1.0	2,899,327	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	51,570,898	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)	78,754,224	32,432,468	45,858,840	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	145,478	22.0	6,613	3.04%	6,483	2.98%	130	0.06%
	Palo Verde Common	03-2027	60 - S0	(2)	1,223,879	346,654	901,803	22.2	40,822	3.32%	39,825	3.25%	797	0.06%
	Total Account 323				338,898,978	140,265,490	205,411,466		9,823,287	2.90%	9,630,674	2.84%	192,613	0.06%
324	Accessory Electric Equipment													

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Attachment RCS-3
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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)
	Palo Verde Unit 1	12-2024	45 - R3	(2)	115,495,170	83,444,066	84,361,007	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	21,962,156	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)	17,916,193	7,299,483	10,977,094	22.0	496,959	2.78%	489,175	2.73%	9,784	0.05%
	Total Account 324				272,676,374	119,058,196	169,060,705		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%	1,024,387	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	82,589	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	887,139,994	1,381,147,598		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 and	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	827,611	827,611	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 Bridge	12-2004	200-SQ	0	77,427	77,427	0	0.0	0	0.00	0	0.00%	0	0.00%
	Hydro Decommissioning Costs					7,884,531	5,335,469	2.0	2,667,735		2,667,735	100.00%	0	0.00%
	TOTAL HYDRO PRODUCTION PLANT				2,681,066	10,658,747	5,222,319		2,667,735		2,667,735		0	
	OTHER PRODUCTION PLANT													
341	Structures and Improvements													
	Douglas CT	06-2017	80 - S1	(5)	4,562	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%	375	0.11%
	Saguaro CT	06-2017	80 - S1	(5)	1,288,525	468,971	865,980	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)	3.8	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	4,803,538	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				9,867,772	4,168,576	5,965,809		260,375	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	44,562	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	388,140	14.0	27,561	1.92%	26,248	1.83%	1,313	0.09%
	West Phoenix Combined Cy	06-2031	70 - S1	(5)	19,343,993	2,849,135	17,682,058	27.0	637,619	3.30%	607,257	3.14%	30,363	0.16%
	Yucca CT 1 - 4	06-2016	70 - S1	(5)	3,232,217	2,559,228	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	5,679,324	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	8,102,851	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	8,802,638	8,220,272	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 (8) 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				32,506,644	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	8,933,061	3,289,918	3,643,183	7.6	487,072	6.74%	487,072	6.74%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	37 - R3	0	4,115,101	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	5,395,616	4,370,146	1,025,870	11.6	88,420	1.64%	88,420	1.64%	0	0.00%
	Total Account 344				109,504,078	29,393,951	81,748,631		3,705,186	3.38%	3,705,186	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	27.6	336,788	2.82%	336,788	2.82%	0	0.00%
	Yucca CT 1 - 4	06-2016	50 - S2	0	2,188,526	1,817,969	348,557	13.0	26,612	1.24%	26,612	1.24%	0	0.00%
	Total Account 345				18,383,129	8,721,408	10,661,721		438,525	2.28%	438,525	2.28%	0	0.00%
346	Miscellaneous Power Plant Equipment													
	Douglas CT	06-2017	70 - L1	0	40,913	30,150	10,763	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	987,431	506,533	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				[illegible]	2,621,235	2,757,240		138,878	2.58%	138,878	2.58%	0	0.00%
	TOTAL OTHER PRODUCTION PLANT				202,718,436	80,831,011	128,097,258		5,703,852		5,654,848		49,202	

(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)	27,818,209	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% (s)	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	6,536,127	1.52%	6,538,127	1.52%	0	0.00%
353.5	Station Equipment - SCE 500 I				7,747,282	7,349,383	397,919		251,787	3.25% (s)	251,787	3.25%	0	0.00%
354	Towers and Fixtures		60 - R3	(35)	83,484,531	45,097,386	66,579,751	38.3	1,738,378	2.08%	1,287,685	1.54%	450,690	0.54%
354.5	Towers and Fixtures - SCE 50				13,762,584	17,477,965	(3,725,381)		446,959	3.25% (s)	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	2,478,965	2.72%	1,837,026	2.02%	642,959	0.71%
355.1	Poles and Fixtures - Steel		55 - R3	(15)	83,067,858	22,833,440	72,694,631	46.1	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		30,236	3.25% (s)	30,236	3.25%	0	0.00%
356	Overhead Conductors and Dev		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	28,947,811	(6,294,096)		736,239	3.25% (s)	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%	186,483	1.80%	18,848	0.18%
358	Underground Conductors and		40 - R3	(10)	18,551,254	9,702,854	10,703,626	26.3	406,976	2.19%	369,980	1.99%	36,996	0.20%
	TOTAL TRANSMISSION PLANT				994,274,409	402,048,829	742,093,250		18,897,167		17,879,251		2,617,916	

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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	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	17,966,838	33.1	642,799	2.10%	493,453	1.91%	49,346	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 - V		38 - R0.5	(10)	284,200,711	81,128,434	231,492,348	30.9	7,491,882	2.64%	6,810,802	2.40%	681,080	0.24%
364.1	Poles, Towers and Fixtures - E		50 - R3	(5)	53,919,641	5,801,820	51,013,814	48.6	1,094,717	2.03%	1,042,588	1.93%	52,129	0.10%
365	Overhead Conductors and Dev		53 - O1	(10)	218,858,780	33,437,453	207,305,005	47.7	4,348,017	1.99%	3,950,924	1.81%	395,092	0.18%
366	Underground Conduit		56 - O1	(5)	425,723,118	26,924,767	420,084,505	82.4	5,098,113	1.20%	4,855,348	1.14%	242,767	0.06%
367	Underground Conductors and		29 - L1	(5)	805,605,783	258,685,205	586,915,867	22.9	25,629,514	3.18%	24,409,061	3.03%	1,220,453	0.15%
368	Line Transformers		35 - R3	(5)	486,837,053	236,537,009	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	91,086,516	176,558,776	27.9	6,292,429	2.60%	5,720,390	2.36%	572,039	0.24%
370	Meters		29 - L0	0	81,330,710	34,836,184	56,494,526	21.8	2,598,256	2.84%	2,598,256	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)	25,335,631	3,863,126	26,639,871	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					2,984,184,082	865,761,802	2,300,633,578		72,968,848		68,826,478		4,140,162	
GENERAL PLANT														
390	Structures and Improvements		39 - R1	(15)	98,867,435	24,085,116	87,062,434	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	38,854,946	15,103,632	23,651,314	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 Equip		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	94,309,891	40,877,647	53,532,044	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	481,756	854,648	16.6	51,454	3.85%	51,454	3.85%	0	0.00%

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

TOTAL GENERAL PLANT					273,792,024	101,264,512	187,027,827		13,878,872		13,208,885		368,986	
TOTAL DEPRECIABLE PLANT STUDIED					3,042,432,504	3,166,573,878	5,542,511,184		226,796,123		212,385,824		14,313,299	

(a) [illegible] related to the 500 KV SCE Transmission Line are Depreciated at a [illegible] of 3.35%.

STEAM PRODUCTION PLANT NOT STUDIED					
311	Structures and Improvements - West Phoenix			0	60,895
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	186,319
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			73,839	

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Attachment RCS-3
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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	The Calculated annual accrual (6) is made up of two depreciation components - service life and net salvage: 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				583,584									
303	Miscellaneous Intangible Plant				201,550,375									
Leased Property														
321	Structures and Improvements				1,833,183									
322	Reactor Plant Equipment				9,670,223									
323	Turbogenerator Units				2,705,885									
324	Accessory Electric Equipment				944,784									
325	Miscellaneous Power Plant Equipment				563,136									
361	Structures and Improvements				195,612									
368	Line Transformers				179,394									
371	Installations On Customers Premises				80,388									
390	Structures and Improvements				11,180,324									
397	Communication Equipment				246,838									
TOTAL OTHER PROPERTY NOT STUDIED					228,566,377	120,727,788								
TOTAL DEPRECIABLE PLANT IN SERVICE					3,389,701,276	3,348,106,325								
NONDEPRECIABLE PLANT														
310	Land and Land Rights				3,295,268									
320	Land and Land Rights				3,399,738									
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				28,755,119									
389	Land and Land Rights				7,327,436									
TOTAL NONDEPRECIABLE					91,678,517									
TOTAL PLANT IN SERVICE					3,481,379,793									

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 (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)
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	919,688	57,339,639	46.94	1,221,552	2.14%
344 Generators and Devices									
Redhawk CC Units 1 & 2	6-2057	70 - O4	(3)	546,899,428	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	28,898	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	14,892,138	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	(5)	1,500,000	23,458	1,701,542	54.50	31,221	2.08%
356 Overhead Conductors and Devices									
Redhawk CC Units 1 & 2		5 ∞	(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				

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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 (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)
OTHER PRODUCTION													
341 Structures and Improvements													
West Phoenix CC 4	6-2056	80 - S1	(5)	$3,768,898	$69,749	$3,687,594	49.71	$75,205	2.06%	$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)	57,118,985	919,886	57,339,839	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	13,736,056	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	14,553,568	35.47	410,307	2.87%	$402,262	2.81%	$8,045	0.06%
Saguaro CT 3	6-2047	37 - R3	0	37,658,176	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	667,214,483		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	36,726	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								

DECISION NO. 67744

EXHIBIT
S-19
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
BARRY WONG
Commissioner

IN THE MATTER OF APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, AND TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816

DIRECT

TESTIMONY

OF

MATTHEW J. ROWELL

CHIEF ECONOMIST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 18, 2006

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ATTACHMENT

Work Paper GAD-WP1 1

EXECUTIVE SUMMARY

Staff is recommending that the Commission not adopt APS' proposed Environmental Improvement Charge for the following reasons:

- The EIC would collect revenues from ratepayers based predominantly upon estimated rather than incurred costs.
- The EIC appears to be unique.
- The EIC would include costs that will not be incurred for several years beyond the Test Year.
- The EIC would include funding for projects before they are mandated to be installed on APS' system.
- Regulatory mandates typically build in construction lead times to provide industry sufficient time to comply with mandated regulatory requirements.
- The EIC is derived based upon multiple year revenue requirements that increase the complexity of auditing the charge in the context of future general rate cases and annual EIC reset proceedings.
- The effect of the EIC on APS' interest expense is unclear.
- The annual reset of the EIC could be implemented without Commission approval under APS' proposal.
- The EIC does not address the fundamental financial challenges that APS has identified.
- The environmental impact of implementing the EIC is unclear.

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Matthew J. Rowell. I am the Chief Economist at the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. What is your position at the Commission?

A. I am the Chief of the Telecommunications and Energy section of the Commission's Utilities Division.

Q. Please describe your education and professional background.

A. I received a BS degree in economics from Florida State University in 1992. I spent the following four years doing graduate work in economics at Arizona State University where I received a MS degree and successfully completed all course work and exams necessary for a Ph.D. My specialized fields of study were Industrial Organization and Statistics. Prior to my Commission employment I was employed as a lecturer in economics at Arizona State University, as a statistical analyst for Hughes Technical Services, and as a consulting research analyst at the Arizona Department of Transportation. I was hired by the Commission in October of 1996 as an Economist II. I was promoted to the position of Senior Rate Analyst in November of 1997 and to Chief Economist in July of 2001. In my current position, I am responsible for supervising nine professionals who work on a variety of telecommunications and energy matters.

Q. What is the scope of your testimony in this case?

A. This testimony addresses Arizona Public Service Company's ("APS" or "Company") proposal to establish an Environmental Improvement Charge ("EIC"). Testimonies

submitted by APS witnesses Messrs. Edward Z. Fox and Gregory A. DeLizio address the environmental expenditures forecast for APS over the next several years and the technical functions of the EIC, respectively.[1] Staff's testimony addresses the appropriateness of the EIC proposal as discussed in testimonies sponsored by Messrs. Fox and DeLizio.

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize your Environmental Improvement Charge ("EIC") testimony.

A. Staff recommends that the Commission reject the Environmental Improvement Charge filed by APS. The stated purpose of the EIC is to establish an adjustment mechanism that would provide recovery of substantial capital investment in environmental controls for APS' coal generation facilities.[2] APS originally estimated that environmental improvement changes to the Cholla Power Plant will cost approximately $135 million through the year 2009. In response to Staff Data Request MJR 3-5, APS updated the number to approximately $160 million and also identified six additional Cholla Plant environmental improvement projects estimated to cost approximately $83 million for a combined total of $243 million. APS states that it will recalculate the EIC and update the Direct Testimony of Mr. Edward Z. Fox. The updated data will be addressed by Mr. Gregory A. DeLizio in his Rebuttal Testimony. It should be noted that the updated $160 million in estimated capital expenditures only include mandated projects according to APS.[3] The Company maintains that the acceleration and scale of environmental expenditures have reached a point where an adjustment mechanism is necessary to timely recover the cost of implementing and maintaining environmental improvements.[4]

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[1] Gregory A. DeLizio (GAD), p.3, lines 7-10
[2] EZF, p.2, lines 1-4
[3] APS' response to Staff Data Request MJR 3-5
[4] Edward Z. Fox (EZF), p.2, lines 22-26

Staff believes that APS has not demonstrated that the traditional test year rate base method is insufficient to deal with upcoming environmental requirements. Although many programs have been and likely will be promulgated regarding environmental improvement projects, APS endeavors to go beyond basic compliance.[5] The Company expresses a desire to be proactive and stay ahead of the regulatory curve when it comes to protecting the environment.[6] On the surface, APS' approach seems noble, but Staff will present testimony that supports following a more prudent and traditional path. This course is supported by the realities that deadlines associated with APS' mandated future environmental improvements are uncertain. Actual project completion dates may be amended or delayed[7]. Furthermore, regulatory mandates typically build in reasonable lead periods to allow industry time to comply with mandated environmental improvement projects.[8] Staff's testimony will also address the issues of accounting for rate base and expenses that would have to be removed from general rate case filings if the proposed EIC were authorized by the Commission. In general, Staff does not support collecting funds from Arizona ratepayers, including interest, before costs have been incurred. Staff will also address issues pertaining to recovery of out of test year costs,[9] industry practices, and EIC provisions proposed by APS.

III. DERIVATION OF THE EIC

Q. Can Staff provide an example of how the proposed EIC is derived?

A. Yes. Staff has developed Table 1 to help explain the derivation of the proposed EIC and illustrate how difficult it could be to keep track of EIC-related expenses. Although APS updated actual and estimated capital expenditures from $135 million to approximately

[5] EZF, p.4-5, lines 22-2
[6] EZF, p.6, lines 3-6
[7] Staff Data Request MJR 3-1
[8] APS' response to Staff Data Request MJR 3-5
[9] For example, a maximum amount of only $3.6 million (2.25 percent) of the updated $160 million in Cholla-related environmental improvement projects could have occurred during the Test Year in this rate case.

$243 million, the updated revenue requirements and resultant EIC kWh rate are not expected to be available until Mr. DeLizio updates and files them with his Rebuttal Testimony.[10] However for the purposes of Table 1, the revenue requirement process is expected to remain unchanged after Mr. DiLizio updates the data and files it with his Rebuttal Testimony.

Table 1

Rate Base and Revenue Requirement Derivation

2004-2007 EIC 1 (GAD-WP1, pp.10-12)

(Unit 1 Baghouse only)

($x1000)

YEAR	(A) Projected Capital Expenditures(1)	(B) AFUDC(2)	(C)= (A)+(B) Rate Base	(D) Revenue Requirement(3)
2004	$373	$11	$384	Not Applicable
2005	$3,147	$188	$3,335	Not Applicable
2006	$15,571	$1,094	$16,665	Not Applicable
2007	$3,038	*	$3,038	$2,808
Totals	**$22,129**	**$1,293**	**$23,422**	**$2,808**

*2007 = plant in service year; therefore AFUDC is replaced with a revenue requirement.

(1) See Work Paper EZF-WP9.

(2) AFUDC is accumulated at an 8.73% rate (Schedule D-1, p. 1) that is applied monthly to rate base (Work Paper GAD-WP1, p. 10). (The 8.73% rate includes APS' requested 11.50% cost of equity.)

(3) A 1.6407 revenue conversion factor (Schedule C-3) is included in the $2,808 Revenue Requirement (RR). The RR is shown in Work Paper GAD-WP1, p. 2 and in Attachment 1.

[10] APS' response to Staff Data Request MJR 3-5

Q. What is the purpose of Table 1?

A. The purpose of Table 1 is to summarize revenue requirements associated with Project EIC 1 used, in part, to develop the EIC kWh rate proposed for Calendar year 2007 (Work Paper GAD-WP1, p. 2), and to illustrate the complexity of the process used in developing EIC revenue requirements as illustrated in Attachment 1. In an attempt to simplify explaining the derivation of the EIC revenue requirement, Staff focused on the Cholla Unit 1 Baghouse Project (EIC 1) proposed to begin in the year 2007. Staff chose this project as its example simply because it represents the first data entry on Work Paper GAD-WP1, p.2.

Q. Please continue your discussion of Table 1.

A. Column (A) in Table 1 contains an excerpt of data contained in Work Paper GAD-WP1 and Work Paper EZF-WP9. Column (A) is the starting point for developing EIC rates because it lists projected capital expenditures for EIC-related projects as reported by APS.

Q. What is the purpose of Column (B) in Table 1?

A. The purpose of Column (B) is to reflect allowance for funds used during construction ("AFUDC") charges in the years 2004-2006. APS booked the referenced 2004-2006 capital expenditures under construction work in progress ("CWIP") and accumulated the AFUDC as shown in Table 1. The clearest illustration of how the data in Column (B) is derived is contained in Work Paper GAD-WP1, p.10. For example, the $188,000 shown in Column (B) for 2005 is the sum of the twelve AFUDC entries listed on p. 10 of Work Paper GAD-WP1. (It should be noted that manually adding the twelve entries equals $192,000. The difference is due to rounding.)

Q. What is the purpose of Column (C) in Table 1?

A. The purpose of Column (C) is to show a $23,422,000 match with total CWIP/AFUDC shown on Work Paper GAD-WP1, p.12.

Q. What is the purpose of Column (D) in Table 1?

A. The purpose of Column (D) is to show a $2,808,000 match with the revenue requirement shown on Work Paper GAD-WP1, p. 2. The derivation of the approximate $2.8 million revenue requirement is shown on Work Paper GAD-WP1, p.12. Staff has also included Attachment 1 to its Testimony to provide an example of the actual calculations used to develop the revenue requirement for January, 2007.

Q. Has Staff prepared any other tables to help in understanding the nature of the proposed EIC?

A. Yes. Staff also prepared Table 2.

Table 2

Summation of Annual Revenue Requirement

2010* EIC 1 (GAD-WP1, p.15)

(Unit 1 Baghouse only)

($x1000)

Expenses		Annual Revenue Requirement
Interest		$507
Equity Return (Grossed-Up)		$2,124
Depreciation		$936
Property Taxes		$324
O&M		$600
Total		$4,491

*2010 = first year to include all expense categories included in Annual Revenue Requirements for EIC 1.

Q. What is the purpose of Table 2?

A. The purpose of Table 2 is to illustrate that the proposed EIC is a "fully loaded" revenue collection mechanism, which includes expenses that are typically and appropriately recovered through rates authorized in a general rate case. Since the revenue requirement process is the same as the methodology described in Table 1, Staff does not address the derivation of the revenue requirements shown in Table 2. The source of the data contained in Table 2 can be found on p. 15 of Work Paper GAD-WP1. Staff's objective with Table 2 is to show revenue requirements far enough in the future to identify all expenses proposed by APS to be included in the EIC. Table 2 focuses on the Cholla Unit 1 Baghouse Project (EIC 1) for the same reasons as discussed under Table 1 and to be consistent with Table 1. The year 2010 was chosen for this illustration because it is the first year in which all Cholla Unit 1 Baghouse expenses are identified by APS.

The annual revenue requirement comes to$4,491,000, also shown in Table 2 and Work Paper GAD-WP1, pp. 2 and 15. Table 2 expenses such as a return on equity grossed-up to cover taxes, depreciation and property taxes are expenses that normally are recovered under the evidentiary processes embodied in general rate cases.

IV. EXPERIENCE IN OTHER JURISDICTIONS

Q. Please discuss the Cambridge Study and its relevance to the EIC being proposed by APS in this rate case.

A. In May 2006, Cambridge Energy Research Associates ("CERA") provided Staff with a preliminary overview of a study being developed to identify methods of recovering costs incurred in installing coal plant environmental improvement projects across the United States. The study is incomplete at this time, but it includes survey responses from 22 states (including Arizona). Respondents represent greater than 81 percent of the listed

MW winter coal generation capacity in the country. A follow-up call to CERA confirmed the relevancy of the data to APS' EIC. The completed study will be available in the near future according to CERA. CERA represented that the Commissions they were aware of either had no surcharges for environmental improvements to coal plants or only allowed surcharges designed to recover expenses that were *actually incurred* in implementing environmental improvement projects. Additionally, in the majority of cases such surcharges are replaced once the utility comes in for a general rate case. In other words, environmental surcharges currently only exist until incurred expenses can be rolled into a general rate case to be recovered through base rates. None of the survey respondents operate under a provision that allows for a "pre-collection" of funds before costs are incurred. The EIC contrasts with industry standards in that the EIC allows for the collection of revenues based upon projected rather than incurred costs.

Q. Has Staff reviewed the NARUC Study[11] of State Incentives included with Mr. Fox's Testimony?

A. Yes. Staff did review the NARUC report on state level incentives for the installation of pollution control equipment. Like the CERA report discussed above, this NARUC study was focused on coal fired power plants. The NARUC study contained responses to a survey obtained from 15 states. None of the 15 responding states has implemented a cost recovery mechanism for environmental improvement projects that is similar to the EIC proposed by APS. The NARUC report cited Wisconsin as a state that has been particularly innovative in the area of financing environmental improvements because of legislation enacted in 2003. However, the legislation enacted in Wisconsin calls for a bond financing scheme that is quite different from APS' proposed EIC.

[11] *A Survey of State Incentives Encouraging Improved Environmental Performance of Base-Load Electric Generation Facilities; Policy and Regulatory Initiatives;* The National Association of Regulatory Utility Commissioners (June 2004).

V. OTHER FACTORS SUPPORTING STAFF'S RECOMMENDATION

Q. Does Staff have additional reasons for its position on the EIC?

A. Yes. APS' responses to Data Requests MR 1-5 and MR 1-6 indicate that APS will continue to book EIC-related projects as increases to rate base for tax purposes. This conclusion is based upon APS' statement that environmental investments which are capitalized will be subject to property taxes. Therefore, a part of property taxes associated with plant would be recovered through base rates and another part would be recovered through the EIC. Each year when APS applies to reset the EIC, it would be Staff's responsibility to verify that the property taxes are allocated appropriately in order to avoid double recovery. The complexity of this task would be compounded should a true up be required between estimated and actual expenses.

APS' responses to Staff Data Requests MR 1-5 and MR 1-6 indicate that, for tax purposes, EIC-related plant will continue to be booked as capitalized plant. It appears that APS would have to create a parallel track for the accounting of EIC-related projects. APS states that the benefits of the EIC approach are the timely recovery of these expenses, sooner implementation of environmental improvements and annual recovery of these capital projects.[12] Unfortunately, under APS' approach Arizona ratepayers would be pre-funding projects that could be constructed later than expected, and at different costs than were originally projected. APS' revisions to the EIC discussed in its response to Staff Data Request MJR 3-5 is an example of why Staff is concerned about using estimated data to fund environmental improvement projects. The updated capital expenditures for the Cholla Plant are $160 million, an increase of $25 million over APS' original proposal. Furthermore, APS identified six additional EIC-related projects that must be added to the EIC. The additional projects are estimated to add approximately $83 million to the

[12] APS' response to Staff Data Request No. MJR 6-1

updated $160 million, for a total of approximately $243 million.[13] In other words, project costs increased $108 million, or 80 percent, in six months compared to data filed by APS on January 31, 2006. Staff recognizes that APS includes a true-up mechanism in the EIC, including interest, but the reality is that APS would construct EIC-related plant using ratepayers - not investors or bond financed - money up front. Staff queried APS about the need for creating pre-construction funds for planned voluntary emissions reduction projects.[14] APS acknowledged that pollution control bonds have been used in the past to finance environmental pollution control projects. It was also acknowledged that pollution control bonds are less costly than taxable financing, but as pointed out by APS, the interest on these bonds is passed along to ratepayers. It is not clear to Staff that the EIC will result in interest expense savings because the proposed EIC includes a provision to pass along an interest expense component to ratepayers. Attachment 1 clearly shows that the EIC interest component is based upon the cost of long term debt (similar to the cost of pollution control bonds). Also, the true-up mechanism adds another interest component to the EIC. At this time Staff can not determine with any certainty that total interest charges will be less under the EIC compared to interest charges incurred with pollution control bonds. Additionally, under the proposed EIC, APS' ratepayers would not receive the tax benefit of pollution control bonds.

Q. The above answer refers to interest expense related to the proposed true up mechanism. Please explain.

A. APS is proposing to include interest as a part of any under or over collection identified in the true-up process.

[13] APS' response to Staff Data Request No. MJR 3-5, Attachment APS 10399
[14] Staff Data Request No. MJR 6-1

Q. Some parties to this case may view the EIC as a mechanism that is conceptually similar to customer advances for construction. Do you agree with this analogy?

A. No. There are significant differences in concept and application between customer advances for construction ("CAC") and the EIC proposed by APS. In many cases, CACs are refundable, and the FERC has established Account 252 to accommodate a refund provision. Even in cases where non-refundable contributions are made by or on behalf of customers for customer-initiated plant projects, the contribution is usually based on the difference between the embedded investment and estimated incremental revenue per customer, and the estimated cost of the project. These allowances traditionally remove or substantially offset depreciation, O&M and property tax expenses. There is no offset to these expenses in the EIC. Additionally, CACs are generally paid within a short time period of when the related construction expenditures are made.

Q. What other factors contributed to Staff's recommendation that the Commission reject the EIC proposed by APS?

A. Staff is concerned about three additional aspects of the proposed EIC: 1) collecting revenues from customers based on estimated data; 2) the EIC creating the need for a more complex auditing process; and, 3) the potential for billing customers for EIC-related expenses without Commission approval.

1. <u>Estimated Data</u>

Under APS' proposal EIC collections would begin in January 2007 based upon costs that would not have been incurred until, at the earliest, sometime during 2007. Furthermore, the collections would be based largely upon estimated data. Nearly all of the originally reported $135 million in capital expenditures is based upon estimated, rather than actual, capital expenditures (Work Paper GAD-WP1, p.59). Even after capital expenditures were

updated to approximately $243 million, estimated costs still represent 97 percent of total costs (APS' response to Data Request MJR 3-5, Attachment APS 10399). And as discussed earlier in Staff's Testimony, estimated costs for the Cholla Plant increased 80 percent in as little as six months from the January, 2006 filing date. Accurately estimating the cost of environmental improvement projects is, at best, an inexact science.

2. Auditing

Another factor influencing Staff's recommendation that the Commission reject the proposed EIC is that Staff would be required to audit EIC-related fund balances by project. For example, none of the originally reported $135 million in capital expenditures should be included in Test Year rate base. APS provided what initially appeared to be a validation of this conclusion by Staff in its response to Staff Data Request MJR 3-4. As a follow up, APS was asked to corroborate that the referenced project costs are not included in the Test Year AFUDC portion of Cost of Service rate base (Staff Data Request MJR 6-4). APS responded that $66,000 of the referenced project costs is included in the Test Year AFUDC portion of Cost of Service rate base. The "double counted" $66,000 rate base/CWIP is de minimis in this rate case. However, the issue is the introduction of yet another rate base revenue producing component, which increases the complexity of tracking plant-driven revenue requirement requests in future rate cases. Furthermore, the EIC would remove eligible environmental improvement plant from general rate case review and constraints. For example, cost recovery of these expenses would be passed on to ratepayers without regard to Test Year constraints.

Q. Verifying APS' Power Supply Adjustor ("PSA") revenues and expenses appears to be a manageable task. Why would the EIC be any different?

A. Verifying APS' PSA revenues and expenses is a manageable project because closing figures from month 1 provide a continuous and verifiable audit trail for month 2. Auditing the EIC will be a far more complex process, because general rate cases are not monthly events and the "double counted" $66,000 mistake discussed above could be compounded into millions of dollars and multiple projects between general rate cases.

3. **Billing The EIC Without Commission Approval**

According to Attachment GAD-2, p.2, Staff would have to review the proposed EIC annually after March 15, 2008 when APS files for the reset of the EIC. In the absence of Commission approval before July 1 of the applicable billing period, APS will automatically start billing customers the proposed EIC as though it had been approved by the Commission. Staff believes that it is inappropriate to implement customer charges without Commission approval. A subsequent true-up mechanism does not properly address the issue of possibly passing on charges to ratepayers that are incorrect and higher than they should be. Even if the Commission decides to reject Staff's recommendation and approve the EIC, this automatic approval provision of the EIC should be removed.

Q. Has Staff considered the financial impact of rejection of the EIC on APS?

A. Yes. Staff is well aware of the financial issues APS is currently confronting. However, APS has identified customer growth and increased fuel costs as the primary drivers behind their current need for a rate case.[15] APS projects that capital investments in the amount of approximately $1.4 billion[16] will be needed to expand its transmission and distribution facilities to serve its native load for the years 2007 through 2009. This amount dwarfs the

[15] See the direct testimony of APS witness Steven Wheeler.
[16] EZF, p.19, line 2

$243 million EIC. Since the EIC does not address the fundamental issues (as identified by APS) that are affecting APS' financial situation (customer growth and fuel costs) Staff does not believe that its rejection will place a significant financial burden on the company.

Q. Has Staff considered the environmental impact of rejection of the EIC?

A. Unfortunately, forecasting the environmental benefits of approval of the EIC would be a difficult task. APS has not provided estimates of the environmental benefit that could be associated with the EIC. Additionally, it does not appear as though APS or any other entity has attempted to calculate such benefits.[17]

Q. Please summarize Staff's recommendation.

A. The Commission should reject APS' request to implement the Environmental Improvement Charge for the following reasons:

- The EIC would collect revenues from ratepayers based predominantly upon estimated rather than incurred costs.
- The EIC appears to be unique. Staff is not aware of any jurisdiction that employs a mechanism with the same characteristics as the EIC.
- The EIC would include costs that will not be incurred for several years beyond the Test Year.
- The EIC would include funding for projects before they are mandated to be installed on APS' system.
- Regulatory mandates typically build in construction lead times to provide industry sufficient time to comply with mandated regulatory requirements.

[17] See response to MR 1-1(b)

- The EIC is derived based upon multiple year revenue requirements that increase the complexity of auditing the charge in the context of future general rate cases and annual EIC reset proceedings.
- The effect of the EIC on APS' interest expense is unclear.
- The annual reset of the EIC could be implemented without Commission approval under APS' proposal.
- The EIC does not address the fundamental financial challenges that APS has identified.
- The environmental impact of implementing the EIC is unclear.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EIC 1 Cholla Unit 1 Baghouse
2005-2011
($000s)

GAD_WP1

Capital Expenditures	2007 January 253	2007 February 253	2007 March 253	2007 April 253	2007 May 253	2007 June 253	2007 July 253	2007 August 253	2007 September 253	2007 October 253	2007 November 253	2007 December 253
Net Plant												
Beginning Balance (1)												
CWIP	20,637	20,890	21,143	21,397	21,650	21,903	22,156	22,409	22,662	22,916	23,169	23,422
AFUDC E/D based on Pre-Total	-	-	-	-	-	-	-	-	-	-	-	-
Total CWIP/AFUDC	20,637	20,890	21,143	21,397	21,650	21,903	22,156	22,409	22,662	22,916	23,169	23,422
Gross Plant In Service												
Accumulated Depreciation												
Net Plant In Service												
Tax Depreciation												
Cumulative Deferred Tax												
Rate Base												
Revenue Requirement												
(1) Interest Expense	42	43	43	44	44	45	45	46	46	47	48	48
(2) Return on Equity - Tax Gross Up	177	179	181	183	186	188	190	192	194	196	199	201
Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Monthly Revenue Requirement	219	222	225	227	230	233	235	238	241	243	246	249
Annual Revenue Requirement												*2,808*

Cap. Expenditures	
2005	3,147
2006	15,571
2007	3,038
2008	-
2009	-
2010	-
2011	-

Depreciation Life	
Years	25

Monthly Tax Depreciation Rates	
2008	0.313%
2009	0.802%
2010	0.567%
2011	0.515%

O&M Expense	
Monthly	60

(1) $20,637 x [2.46%/12-months] = $42.31

(2) $20,637 x [6.27%/12-months] x 1.6407 = $176.91

EXHIBIT
S-20
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
BARRY WONG
Commissioner

IN THE MATTER OF THE AMENDED 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 TO AMEND DECISION NO. 67744.	)	DOCKET NOS. E-01345A-05-0816 E-01345A-05-0826 E-01345A-05-0827

SURREBUTTAL

TESTIMONY

OF

MATTHEW J. ROWELL

CHIEF ECONOMIST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEMBER 27, 2006

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NOS. E-01345A-05-0816 ET AL

This Surrebuttal Testimony will address Arizona Public Service Company's rebuttal testimonies pertaining to the proposed Environmental Improvement Charge ("EIC") as submitted by Messrs. Edward Z. Fox and Gregory A. DeLizio. Staff continues to oppose adoption of the EIC.

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Matthew J. Rowell. I am the Chief Economist at the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Matthew Rowell who submitted prepared Direct Testimony in this Docket?

A. Yes.

Q. What is the purpose of your Surrebuttal Testimony?

A. This Surrebuttal Testimony will address Arizona Public Service Company's ("APS" or "Company") rebuttal testimonies pertaining to the proposed Environmental Improvement Charge ("EIC") as submitted by Messrs. Edward Z. Fox and Gregory A. DeLizio.

II. REPLY TO REBUTTAL TESTIMONY OF EDWARD Z. FOX

Q. At page 3 lines 1 thru 4 of his Rebuttal Testimony Mr. Fox summarizes his perception of Staff's concerns. Please comment.

A. Here Mr. Fox lists three of the many concerns with the EIC discussed in my Direct Testimony: It is unique, its impact on the environment is unclear, and it seeks to recover estimated future costs of projects not yet mandated. Mr. Fox characterizes these issues as Staff's "major concerns." While these issues were discussed in my Direct Testimony they were not singled out as being Staff's "major concerns." Staff is opposing the EIC because of all the concerns listed in my Direct Testimony and restated below:

- The EIC would collect revenues from ratepayers based predominantly upon estimated rather than incurred costs.

- The EIC appears to be unique. Staff is not aware of any jurisdiction that employs a mechanism with the same characteristics as the EIC.
- The EIC would include costs that will not be incurred for several years beyond the Test Year.
- The EIC would include funding for projects before they are mandated to be installed on APS' system.
- Regulatory mandates typically build in construction lead times to provide industry sufficient time to comply with mandated regulatory requirements.
- The EIC is derived based upon multiple year revenue requirements that increase the complexity of auditing the charge in the context of future general rate cases and annual EIC reset proceedings.
- The effect of the EIC on APS' interest expense is unclear.
- The annual reset of the EIC could be implemented without Commission approval under APS' proposal.
- The EIC does not address the fundamental financial challenges that APS has identified.
- The environmental impact of implementing the EIC is unclear.

Q. In the question at page 4 lines 10 thru 13 Mr. Fox states that "...Staff identifies Wisconsin as being innovative..." Please comment.

A. Mr. Fox's comments here indicate that a clarification of my Direct Testimony may be necessary. In my Direct Testimony, I merely pointed out that *the authors of the NARUC study*[1] held Wisconsin out as a particularly innovative state. Staff was not advocating for a similar approach in Arizona. Staff's discussion of the NARUC study was simply meant

[1] *A Survey of State Incentives Encouraging Improved Environmental Performance of Base-Load Electric Generation Facilities; Policy and Regulatory Initiatives;* The National Association of Regulatory Utility Commissioners (June 2004).

to highlight the fact that APS' proposed EIC is unique. Staff is not aware of any other state with a mechanism quite like the EIC. At page 11 line 6 of his testimony Mr. Fox concedes the point that the EIC is unique.

Q. At page 5 lines 7 thru 23, Mr. Fox lists several states (Florida, Indiana, West Virginia, and Kentucky) that have environmental cost recovery programs. Please comment.

A. Staff believes that the EIC proposed by APS is more radical than each of the state programs Mr. Fox discusses here. As Staff understands these programs, none of them allow for recovery based on the *estimated* costs of future projects.

Q. At page 10 lines 13 thru 20 Mr. Fox indicates that the standard for review based on prudence contained in "the traditional ratemaking process" is problematic. Please comment.

A. Here it appears that APS is concerned about a negative prudence determination regarding environmental improvements. Staff will just note here that this prudence concern could be addressed without a surcharge mechanism like the EIC. The Commission has established processes to address similar prudence concerns arising from the construction of natural gas infrastructure investments.[2] This process allows for pre approval of such investments given certain circumstances. While Staff is not advocating such a program at this time, we believe it is worth noting that such a program is substantially less radical than the proposed EIC and would address the concerns with prudence determinations that Mr. Fox discusses on page 10 of his rebuttal testimony.

[2] See the Commission's December 18, 2003 Policy Statement Regarding New natural Gas Pipeline and Storage Costs.

III. REPLY TO REBUTTAL TESTIMONY OF GREGORY A. DELIZIO

Q. At page 3 lines 21 and 22 of his Rebuttal Testimony Mr. DeLizio implies that Staff would require the company to quantify the environmental benefits of emission control equipment before a project can be funded. Please comment.

A. In my Direct Testimony I did comment on the uncertainty of the environmental benefit of the EIC. However, my Direct Testimony did not state that the environmental benefit of emission control equipment needs to be quantified before a project can be funded. That is simply not Staff's position.

Q. At page 3 line 23 thru page 4 line 7, Mr. DeLizio discusses the financial impact of Staff's recommendation not to adopt the proposed EIC. Please respond.

A. First, Mr. DeLizio states that Staff contends that "the denial of timely recovery of these types of costs would not impose a significant financial burden on the company…" Again, this is a misinterpretation of Staff's position. Staff is not opposed to the timely recovery of prudently incurred costs and Staff does not believe that the denial of timely recovery has no financial impact on the company. The real point of disagreement between Staff and APS has to do with what is considered to be "timely." Staff believes that the traditional ratemaking process does provide for timely recovery of costs. The company believes otherwise. However, Staff does not believe that the company has made the case that the radical departure from the traditional ratemaking process envisioned by the EIC is necessary in order to ensure timely recovery.

Next, Mr. DeLizio contends that Staff's analysis of the EIC has missed "the key point in this entire proceeding, which is discussed in the rebuttal testimony of Mr. Wheeler. Capital is at a premium for APS and without the EIC, environmental projects are just another capital need in a very long line of competing needs." Staff understands this point:

money spent on environmental improvements has the same financial impact on APS as money spent on any other capital improvement. However, APS chose to single out the cost of environmental improvements for a surcharge. Mr. Wheeler identifies customer growth as the driver of the company's financial concerns.[3] However, the company has not proposed a surcharge to cover the capital costs associated with customer growth.

Implementation of the EIC could cause customers to blame their increased rates on the cost of environmental improvements. However, the company contends that customer growth is the driver of the company's financial concerns and thus its need for increased rates. This disparity between the Company's claimed cause of its financial concerns and its proposal to deal with those concerns is striking.

IV. SUMMARY

Q. Please summarize Staff's position on the EIC.

A. For the reasons cited in my Direct Testimony, Staff does not support adoption of the EIC at this time.

Q. Does Staff have any other comments at this time?

A. Yes. Staff recognizes and appreciates APS' commitment to environmental issues (as exemplified by the EPA's selection of APS to receive the 2006 Climate protection Award.) Staff's testimony concerning the EIC should not be construed in any way to reflect negatively on APS' record with regard to environmental issues. Staff has viewed the EIC as a ratemaking issue, not an environmental policy issue.

[3] Also, Mr. Fox identifies customer growth as a challenge to its environmental commitments. See page 18 lines 16-17 of Mr. Fox's Rebuttal Testimony.

Q. Does this conclude your testimony?

A. Yes.

ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

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 TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827

STAFF'S NOTICE OF FILING

Staff of the Arizona Corporation Commission hereby provides notice of filing the Supplemental Testimony of Matthew J. Rowell regarding the establishment of a rate stabilization fund for APS in the above-referenced matter.

RESPECTFULLY SUBMITTED this 14th day of November, 2006.

Arizona Corporation Commission
DOCKETED
NOV 14 2006
DOCKETED BY nr

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SUMMARY OF THE RESPONSE TO COMMISSIONER INQUIRIES REGARDING THE ESTABLISHMENT OF A RATE STABILIZATION FUND FOR APS
STAFF WITNESS
MATTHEW ROWELL

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

Several letters from Commissioners filed in this docket have inquired about the establishment of a mechanism similar to SRP's rate stabilization fund for APS. I will be addressing Staff's views on the establishment of such a mechanism for APS during my oral testimony on November 20 or 27, 2006. To summarize Staff's position: While a rate stabilization fund is a novel idea with potential benefits, Staff does not support the adoption of a rate stabilization fund for APS at this time. In general, rate stabilization funds suffer from a fundamental flaw: they require up front funding which imposes up front costs. Such costs may need to be supported by ratepayers. Also, given the size of recent actual and requested APS rate increases, any hypothetical rate stabilization fund would have had to have been very large (and thus very expensive) to make a meaningful difference in rate impact. With respect to SRP's rate stabilization fund, Staff notes that SRP is a fundamentally different type of entity than APS and thus policies that are appropriate for SRP may not be appropriate for APS; in fact they may not even be possible. For instance when SRP's rate stabilization fund was established, SRP had $55 million at its disposal to deposit into the fund.

EXHIBIT
S-22
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
BARRY WONG
Commissioner

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 TO AMEND DECISION NO. 67744.	)	DOCKET NO. E-01345A-05-0816

DIRECT

TESTIMONY

OF

ERINN A. ANDREASEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEMBER 1, 2006

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Schedule – Typical Bill Analysis for Informational Scenario EAA-6

APS Customer Transition Plan ..... Exhibit A

APS Revised Schedule 1 ..... Exhibit B

APS Revised Schedule 3 ..... Exhibit C

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

Ms. Andreasen's testimony recommends the following:

1. Staff recommends higher than average increases for rate schedules E-34 and E-35 based on the fact that these categories are under performing relative to the rest of the general service class and the system-average rate of return.

2. Staff recommends that the cost-of-service category E-32 (1,000 or greater kW) receive a greater increase than E-32 cost-of-service categories (0-20 kW), (21-100 kW), (101-400 kW), and (401-999 kW).

3. Staff recommends that rate schedule E-20 receive a much smaller than average increase due to the fact that its return is much greater than the system average and exceeds the returns for the other rate categories in the cost-of-service study.

4. Staff recommends that APS provide a 12-month interim period for customer transition so that residential customers on E-10 and EC-1 will have additional time to fully evaluate their alternative rate options. Staff also recommends that APS continue customer outreach efforts to educate consumers about their rate options during the 12-month interim period.

5. Staff recommends that E-10 and EC-1 not be cancelled until the end of the 12-month interim period, which should provide customers with adequate time to consider alternative rate options.

6. Staff recommends that APS provide customers on E-21, E-22, E-23, and E-24 a six-month interim period for customer transition so that customers would be provided adequate time to consider other rate options and allow APS time to switch out meters where required. Staff also recommends that APS propose an interim rate increase to apply during the interim period for rates E-21, E-22, E-23, and E-24 that is greater than the average increase for the general service class.

7. Staff recommends that E-21, E-22, E-23, and E-24 not be cancelled until the end of the six-month interim period, which should provide customers with time to consider alternative rate options.

8. Staff recommends that rate designs for residential rates ET-2 and ECT-2 remain revenue neutral when compared to rates adopted for ET-1 and ECT-2 respectively.

9. Staff recommends that the proposed demand rates for E-32 not be raised significantly over levels proposed by APS.

10. Staff recommends that in the next rate case filed with the Commission, APS propose to replace general service rate schedule E-32 with alternate general service schedules that divide E-32 usage into small, medium, and large categories or other appropriate division.

11. Staff recommends that the System Benefit Charge for all applicable APS rate schedules be set at $.001850 per kWh.

12. Staff recommends that the after-hours charge on Schedule 1 for other services remain at $75.00 per trip.

13. Staff recommends that APS include a definition for Multi-Unit Residential High-Rise Developments on Schedule 1.

14. Staff recommends that APS should add clarifying language to Schedule 3 to specify that the "construction cost" refers to the "backbone infrastructure cost."

15. Staff recommends that under sections titled Master Planned Community Developments and Residential Multi-Family Developments of Schedule 3, APS clarify that allowances will be credited to the applicant.

16. Staff recommends that APS amend its definition for "Residential Homebuilder Subdivision" on Schedule 3 to be consistent with R14-2-201(34). Staff also recommends that APS alphabetize the definitions included on Schedule 3.

17. Staff recommends that APS add language to each section of Schedule 3 clarifying the applicable timeframes for field audits and refundable advances.

18. Staff recommends that APS should file a revised Schedule 3 including Staff's recommendations above in its rebuttal testimony. In its rebuttal testimony, APS should provide a copy of its proposed Schedule 3 redlined against the current version attached to my testimony as Exhibit B

19. Staff recommends that the Commission open a generic docket where parties can provide feedback and the Commission can evaluate the adoption of hook-up fees for the energy industry.

20. Staff recommends that APS establish a forum to explore issues associated with demand-response and load-management opportunities for its service territory.

21. Staff recommends that APS conduct a study that identifies which types of demand-response and load-management programs would be most beneficial to APS' system. In the study, APS should demonstrate why certain programs are more beneficial than others and identify which customer segments would be most likely to respond to such programs. The study should rely on a cost-benefit analysis based on the Societal Cost Test and be filed with the Commission within eight months of approval of a decision in this matter. In addition, APS should be required to file for Commission approval of one or more cost-

effective demand-response or load-management programs that APS believes would be most beneficial to its system and its ratepayers, and to file it concurrently with the filing the study referred to above.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Erinn Andreasen. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background and professional experience.

A. In 1999, I graduated summa cum laude from Arizona State University, receiving a Bachelor of Science degree in Agribusiness with a specialization in international business. In 2003, I received a Masters Degree in Business Administration from the University of Phoenix with a specialization in global business. I have worked at the Commission for over six years as an Economist and a Public Utilities Analyst. My current duties include the evaluation of electric utility special contracts, demand-side management programs, utility tariff filings, rate design, and applications for competitive electric Certificates of Convenience and Necessity.

Q. As part of your employment responsibility were you assigned to review matters contained in Docket No. E-01345A-05-0816?

A. Yes.

Q. What is the scope of your testimony in this proceeding?

A. My testimony will address Staff's proposed revenue allocations and rate design, APS' proposed customer transition plan, APS' proposed changes to Schedule 1 and Schedule 3, general issues related to the establishment of hook-up fees, and demand-response and load-management programs.

REVENUE SPREAD

Q. Please identify the overall increase that Staff has proposed.

A. As discussed in the testimony of Staff witness Mr. Jim Dittmer, Staff is recommending an overall increase of $203,993 million in revenue from rates. Staff's recommended increase would result in approximately a 9.57 percent increase to revenues from rates.

Q. Did you rely on the result of the cost-of-service study referred to by Staff witness Mr. Mike Brosch as a guide in developing Staff's recommended revenue spread?

A. Yes. Mr. Brosch provided the results of his cost-of-service review to Staff. The-cost-of service study demonstrates the degree to which a particular customer class rate of return deviates from the system average. The closer a class rate of return is to the system average the more accurately the class is recovering its embedded cost plus a return. Staff utilized the cost-of-service study results as a guide in determining the amount of the increase that should be assigned to each rate class.

Q. Please identify the customer classes that APS currently utilizes in its cost-of-service model.

A. APS' cost-of-service model breaks down its various customer classifications into five main customer classes. They are residential, general service, water pumping, street lighting, and dusk to dawn. Within the residential class, there are categories for residential rate schedules[1] E-10, E-12, EC-1, ET-1 and ECT-1. Within the general service class, there are categories for E-20, E-30 and E-32 (0-20 kilowatts ("kW")), E-32 (21-100 kilowatt-hours ("kWh")), E-32 (101-400 kW), E-32 (401-999 kW), E-32 (1,000 and greater kW), E-34, and E-35. Some rate schedules are not represented as a separate category and are instead grouped together with other similar tariffs. For instance, the outdoor lighting category

[1] Residential time-of-use rates ET-2 and ECT-2 were approved by the Commission on April 12, 2006, and became effective July 1, 2006. These schedules were not in effect during the test year.

contains rate schedules E-58, E-59, and E-67. In addition, the various E-32 categories include rate schedules E-21, E-22, E-23, E-24, E-32 TOU, and E-66.

Q. Please provide a general summary of the results for the major categories in the cost-of-service study.

A. The results of the cost-of-service study indicate that the residential and street lighting customer classes are earning a return less than the system average; the general service, water pumping, and dusk to dawn classes are earning greater than the system average rate of return. A summary of the rates of return and rate of return index is provided below.

Cost-of-Service Summary

Cost-of-Service Category	Rate of Return	Rate of Return Index (1.00 = system average rate of return for ACC jurisdiction)
Residential	4.25%	0.81
General Service	6.51%	1.25
Water Pumping	8.30%	1.59
Street Lighting	2.18%	0.42
Dusk to Dawn	5.98%	1.15
System Average	5.23%	1.00

A complete summary of the cost-of-service results including the interclass returns under the 4-Coincident Peak ("CP") and 4-CP and Average cost-of-service allocation methodologies is provided as Schedule EAA-1.

Q. Please comment about the interclass returns for the residential cost-of-service category.

A. The residential class overall is earning less than the average rate of return. Within the residential class, rates EC-1, ET-1, and ECT-1 are the weakest performers while rate E-12 is earning slightly more than the system average rate of return. This indicates that EC-1, ET-1, and ECT-1 rate schedules are underperforming relative to the rest of the residential class as well as the system average rate of return and should be given higher than average increases.

Q. Please provide comment about the interclass returns for the general service cost-of-service category.

A. Although the class as a whole is earning a better than average rate of return, the results of the cost-of-service study indicate that returns for the customer groups with the largest customers such as E-32 (1,000 kW or greater), E-34, and E-35 are significantly lower than the rest of the general service class. This general result holds true under both the 4-CP and 4-CP and Average cost-of-service allocation methodologies that were discussed in the testimony of Mr. Brosch. This indicates that these particular customer groups are underperforming relative to the rest of the general service class as well as the system average rate of return and should be given higher than average increases.

Q. Please provide Staff's recommended revenue spread for the major cost-of-service-categories. How did Staff arrive at its overall recommended revenue spread proposals for APS' major cost-of-service classes?

A. Staff's proposed revenue spread is provided below.

Staff's Proposed Revenue Spread for Major Cost-of-Service Categories

Cost-of-Service Category	Rate Increase %	Rate of Return Index (1.00 = system average rate of return for ACC jurisdiction)
Residential	9.69%	0.86
General Service	9.52%	1.19
Water Pumping	6.29%	1.34
Street Lighting	8.92%	0.44
Dusk to Dawn	7.79%	0.89
Total Increase	9.56%	1.00

Staff utilized the cost-of-service results as a guide in determining revenue spread and considered assigning a greater portion of the increase to certain rate schedules or cost-of-service categories that are underperforming. In the process of determining revenue spread, Staff analyzed the effect of inputting the various rate increases for each of the individual cost-of-service categories and compared the impact of those increases to each category's rate of return index. Staff also considered the rate impacts that could potentially result from its proposed revenue spread.

Q. Please provide Staff's recommendations regarding the rate spread for the interclass residential cost-of-service categories. How did Staff arrive at its overall recommended revenue spread proposals for APS' residential cost-of-service classes?

A. Staff's proposed residential interclass revenue spread is provided below. Staff considered two scenarios. The first scenario is Staff's recommended interclass residential rate spread which takes into account the elimination of frozen rate schedules E-10 and EC-1 consistent with Commission Decision No. 67744. In the second scenario, Staff evaluated an

interclass residential rate spread scenario where E-10 and EC-1 would not be cancelled in this proceeding. The latter scenario is being provided for informational purposes only.

Interclass Residential Rate Spread

	Customer Transition		No Customer Transition	
Residential Rate	Scenario #1 Staff Recommended Increase %	Rate of Return Index 1.00 = system average rate of return for ACC jurisdiction)	Scenario 2 Increase %	Scenario #2 Rate of Return Index 1.00 = system average rate of return for ACC jurisdiction)
E-10 (Frozen)	16.42%	1.09	10.36%	.87
E-12	7.21%	1.00	8.91%	1.06
EC-1(Frozen)	17.24%	0.98	10.29%	0.74
ET-1	9.99%	0.78	9.98%	0.78
ECT-1	10.15%	0.67	10.45%	0.68
Total Residential Increase	9.69%	0.86	9.69%	0.86

Under Staff's recommended Scenario #1, Staff has proposed the elimination of E-10 and EC-1. Because APS has proposed that E-12 and ECT-1 would be default rates in the proof of revenue for E-10 and EC-1 respectively, consideration was given to the fact that the E-12 and ECT-1 revenue allocations would be based upon the rate design for E-10 and EC-1. The second scenario is provided to illustrate a scenario where rates E-10 and EC-1 are not eliminated in this proceeding.

In both scenarios, Staff based this rate spread on the results of the cost-of-service study, the impact of the overall increase to ratepayers, and a desire to raise the rates for frozen rate schedules E-10 and EC-1 above the system average increase of 9.56 percent.

Q. What is Staff recommending for the interclass returns for the general service category?

A. Staff's recommended interclass spread for the general service class is provided below.

Staff Recommended Interclass General Service Rate Spread

Cost-of-Service Category	Rate Increase %	Rate of Return Index (1.00 = system average rate of return)
E-20	1.25%	1.25
E-30 and all E-32	9.44%	1.27
E-34	10.26%	0.75
E-35	10.26%	0.50
Total General Service Increase	9.52%	1.19

While Staff is recommending a total increase of 9.52 percent for the general service class as a whole, Staff recommends higher than average increases for rate schedules E-34 and E-35 based on the fact that these categories are under performing relative to the rest of the general service class and the system-average rate of return.

As previously discussed, the cost-of-service category E-32 (1,000 or greater kW) is also underperforming relative to the rest of the general service class and the system-average rate of return. While Staff did not provide proposed rate spreads for the various cost-of-service categories within the E-32 category, Staff recommends that the cost-of-service category E-32 (1,000 or greater kW) receive a greater increase than E-32 cost-of-service categories (0-20 kW), (21-100 kW), (101-400 kW), and (401-999 kW).

Staff also recommends that rate schedule E-20 receive a much smaller than average increase due to the fact that its return is much greater than the system average and exceeds the returns for the other rate categories in the cost-of-service study.

APS PROPOSED CUSTOMER TRANSITION PLAN

Q. What did the decision in APS' last rate case indicate about the elimination of certain rate schedules in APS next rate case proceeding?

A. Commission Decision No. 67744 indicates that APS shall provide notice to customers that frozen rate schedules E-10, EC-1, E-21, E-22, E-23, E-24, E-38, and E-38T will be eliminated in APS' next rate proceeding. The notice was to be provided to customers at the conclusion of the then pending rate case and at the time APS files its next rate case (this currently pending case).[2]

Q. Has APS provided customers notice consistent with the Commission Decision No 67744?

A. Yes. Correspondence from APS indicates that notice was provided to customers on April 2005 and April 2006 customer bills.

Q. What was the rationale behind requesting the cancellation of frozen rate schedules E-10, EC-1, E-21, E-22, E-23, E-24, E-38, and E-38T?

A. Some rate structures such as E-10 and E-12 are duplicative in nature. For instance the rate structure on E-10 is identical to the rate structure on E-12. However, E-10 is priced below E-12. In addition, irrigation rates E-38 and E-38T are very similar to irrigation rates E-221 and E-221-8T. The other rationale to support phasing out these frozen rates is that

[2] Settlement paragraphs 114, 122, and 123.

some of these rates may have a substandard return meaning other rate payers may be subsidizing the costs to serve customers on these rate schedules.

Q. Please provide a brief description of APS' customer transition plan for residential customers.

A. APS' proposed plan is attached as Exhibit A. Residential customers on E-10 and EC-1 would be placed on interim rates at the conclusion of the rate case and given up to six months to review alternate residential rate schedules and to choose a new rate schedule. If E-10 and EC-1 customers have not affirmatively chosen an alternate rate schedule after six months, they would be placed on default rates. A chart showing the proposed residential default rates is provided below.

APS Proposed Residential Default Rates

Residential Rate to be Eliminated	Monthly Usage (annual average)	Default Rate
E-10 and EC-1	Less than 1,000 kWh	E-12 Residential Service Standard Rate
E-10	Greater than 1,000 kWh	ET-1 Residential Service Time of Use Time Advantage (9 p.m. to 9 a.m.)
EC-1	Greater than 1,000 kWh	ECT-1 Residential Service Time of Use with Demand Charge

During the interim period, APS has indicated that it would provide information to affected residential customers about the transition in bill messages, direct mail letters, email messages, and recorded messages provided through outbound direct-dialed phone calls. In addition, APS would provide on-line rate analysis tools that would utilize a customer's actual usage history or general usage assumption in order to compare alternative rate

options. During the test year, APS had approximately 99,100 customers on E-10 and EC-1 combined, representing 11 percent of its residential customer base.

Q. Does Staff have any concerns about APS' proposed interim period of six months for residential customers?

A. Yes. Given the magnitude of the increase, Staff is concerned that customers may require a longer period of time in which to fully evaluate their alternative rate options, including time-of-use. Therefore, Staff recommends that APS provide a 12-month interim period for customer transition so that residential customers on E-10 and EC-1 will have additional time to fully evaluate their alternative rate options. Staff also recommends that APS continue customer outreach efforts to educate consumers about their rate options during the 12-month interim period.

Q. What does Staff recommend regarding the cancellation of rates E-10 and EC-1?

A. Staff recommends that E-10 and EC-1 not be cancelled until the end of the 12-month interim period, which should provide customers with adequate time to consider alternative rate options. During the interim period, an interim rate increase for E-10 and EC-1 would apply. Staff has proposed an interim rate increase and interim rates for E-10 and EC-1 which is discussed later in this testimony.

Q. Please provide a brief proposal of APS' customer transition plan for non-residential customers.

A. Non-residential customers on experimental time-of-use rates E-21, E-22, E-23, and E-24 would be placed on E-32 TOU at the conclusion of the rate case. APS would then provide each customer with a comparison of their bill on E-32 and E-32 TOU via an outbound call to each affected customer. If customers were to find that E-32 was a more advantageous

rate than E-32 TOU, the customer could switch to E-32 as soon as a meter change could be provided by APS. APS would also communicate information about the transition to E-21, E-22, E-23, and E-24 customers in bill messages and direct mail letters. During the test year, APS had approximately 230 customers on these rates combined.

Water pumping customers on E-38 and E-38T would be transferred to E-221 Water Pumping Service at the conclusion of the rate case. APS would communicate information about the transition to non-residential customers in bill messages. During the test year APS had 44 customers on this rate.

Q. Does Staff have any recommendations about APS' customer transition plan for general service customers?

A. Yes. Although E-21, E-22, E-23, and E-24 are time-of-use rates, due to differing customer usage characteristics, some customers on these rate schedules may have a lower bill on E-32 as opposed to E-32 TOU. Staff does not believe it is appropriate to automatically switch customers to E-32 TOU until they have had an opportunity to consider other rate options. For residential customers, Staff has recommended an interim period of 12 months. Staff believes an interim period should also be adopted for E-21, E-22, E-23, and E-24. Therefore, Staff recommends that APS provide customers on E-21, E-22, E-23, and E-24 a six-month interim period for customer transition so that customers would be provided adequate time to consider other rate options and allow APS time to switch out meters where required. Staff also recommends that APS propose an interim rate increase to apply during the interim period for rates E-21, E-22, E-23, and E-24 that is greater than the average increase for the general service class.

Q. What does Staff recommend regarding the cancellation of rates E-21, E-22, E-23, and E-24?

A. Staff recommends that E-21, E-22, E-23, and E-24 not be cancelled until the end of the six-month interim period, which should provide customers with time to consider alternative rate options.

Q. Does Staff object to APS' proposal to transition E-38 and E-38-T customers directly to E-221 and E-221-8T?

A. No. E-221 and E-221-8T are the most applicable rate options for these irrigation customers.

Q. When transitioning customers to alternate rates, is there a potential for unintended rate impacts to certain customers?

A. Yes. When redesigning a rate or when cancelling rates and transitioning customers to alternate rate structures, there may be some customers who will experience unintended rate impacts. APS' proposal to transition residential E-10 and EC-1 customers (greater than 1,000 kWh) to time-of-use default rates appears to mitigate certain adverse rate impacts that would have occurred otherwise. However, some customers who are not accustomed to time-of-use rates may not be willing or able to shift their load which can cause adverse rate impacts. Similar impacts could occur for general service customers. For instance, APS' proposal would automatically transfer customers to rate E-32 TOU. While these customers may be accustomed to shifting load, there could also be unintended rate impacts based on individual load factors and differences in rate structures.

RATE DESIGN

Q. Is Staff proposing rate designs for a full set of APS rates?

A. No. Staff is providing bundled rate design proposals for residential rate schedules E10, E-12, EC-1, ET-1, ET-2, ECT-1, and ECT-2 under Staff's proposed residential rate spread and optional scenario discussed above. Staff is also identifying certain recommendations that should be followed when setting APS rates and revenue spread. The rates to ultimately be adopted by the Commission will be influenced by changes to revenue requirements and other decisions made by the Commission.

Q. Please summarize APS' approach to designing its proposed residential rates.

A. APS has proposed maintaining the current basic service charge, increasing the differentials between on- and off-peak periods, as well as the differentials between summer and winter periods. APS has applied the proposed increase to both demand and energy components of its rates. The majority of APS' proposed increase has been applied to residential unbundled generation rates. For some rates, smaller increases have also been applied to APS' unbundled delivery or distribution rates.

Q. Do Staff's proposed residential rates generally follow the same approach utilized by APS?

A. Yes. Staff's rates also maintain the current basic service charge, increase the differentials between on- and off-peak periods, and the differentials between the summer and winter periods. However, Staff's proposed rates reflect differences associated with the revenue requirement recommended by Staff and Staff's proposed revenue spread. A summary of Staff's recommended residential rates is provided as schedule EAA-2. For informational purposes, Staff has also provided a set of residential rates under the informational rate

spread scenario #2 where E-10 and EC-1 would not be cancelled in this proceeding. These rates are provided on schedule EAA-3.

Q. Please describe Staff's proposed rate design for residential rate E-12.

A. E-12 is a seasonal rate with three kWh blocks (first 400 kWh, next 400 kWh, and all additional kWh) applying to the summer period and a flat per kWh rate during the winter period. Under Staff's proposed rate design for the E-12 summer rate, the rate for the first block has been increased by 8.00 percent, the second block has been increased by 9.48 percent, and the third block has been increased by 10.05 percent. This proposed rate design (resulting in the second block 41 percent greater than the first, the third block 17% greater than the second block, and the third block 65% greater than the first block) increases the pricing differentials between APS' rate blocks when compared to current rates. This type of rate design also sends price signals consistent with energy conservation goals.

Q. Commission Decision No. 67744 ordered APS to investigate the impact of lowering the first block to 350 kWh and the second block to the next 350 kWh while reducing the rate in the fist block and increasing the rate for the third block. Is Staff opposed to such a proposal?

A. No. Staff is not opposed. While Staff did not propose changing the current rate blocks, Staff does not find this proposal to be detrimental to APS' customers.

Q. Please identify the total Staff proposed rate increase for an E-12 customer including applicable surcharges and adjustor rates for the peak summer month during the test year.

A. Based on average use (981 kWh) during the peak summer month of July 2005, an E-12 customer would have an increase of $8.88 or 7.69 percent, and based on the median use

(818 kWh) for that same period, an E-12 customer would have an increase of $6.86 or 7.36 percent. A breakdown of a customer bill for the peak summer month is provided on schedule EAA-4.

Q. Has Staff considered ways of mitigating the impact of the rate increase on low income customers?

A. Yes. Staff believes that the Commission may want to consider increasing the discount on E-3 and E-4 for customers with usage between 801-1,200 kWh. This usage block on E-3 and E-4 would include the majority of average use customers. Currently, the discount is 14 percent. Staff has considered the option of increasing the discount. If the discount is increased, this will affect the amount to be collected through the system benefits charge.

Q. Has Staff proposed an interim rate increase for rates E-10 and EC-1 that would be in effect during the interim period discussed previously?

A. Yes. Staff has proposed a set of rates that would be in effect during the interim period. Staff's rates are designed to gradually step customers' rates up toward the default rates that they may transition to at the end of the interim period. Staff's recommended E-10 and EC-1 rates are identical to the rates provided in Staff's informational rate spread scenario where E-10 and EC-1 would not be cancelled in this proceeding. The E-10 rate class would receive a revenue increase of about 10.36 percent and the EC-1 class would receive a revenue increase of about 10.29 percent.

Q. Has Staff completed a typical bill analysis for its recommended residential rates and informational rate spread scenario?

A. Yes. Staff has provided rate impacts for certain recommended rates with Customers transitioning to alternate rates and an informational rate spread scenario where customers

would not transition to new rates as a result of cancelling E-10 and EC-1. A Typical Bill analysis for Staff's recommended rates is provided as EAA-5. A typical bill analysis for rate schedules under Staff's informational rate spread scenario #2 is provided as EAA-6.

Q. Experimental time-of-use rates ET-2 and ECT-2 became effective on July 1, 2006. Does Staff have any recommendations regarding these rates?

A. Yes. Staff proposed increases to these rates so that ET-2 and ECT-2 remain revenue neutral with ET-1 and ECT-2 respectively. In addition, the rates have been designed to achieve close to the current peak to off-peak kWh ratios in the summer and winter periods. Staff recommends that rate designs for residential rates ET-2 and ECT-2 remain revenue neutral when compared to rates adopted for ET-1 and ECT-2 respectively.

Q. Please summarize APS' proposed rate design for general service rate E-32.

A. APS has assigned an increase of approximately 21 percent to rate schedule E-32 which represents the APS proposed system average increase. In addition, APS has maintained the current rate structure and applied the majority of the increase to unbundled generation components while applying a much smaller increase to the delivery or distribution component. In its proposed rate design, APS has proposed increases to both energy and demand rate elements. However, the majority of the increase has been allocated to energy rate elements.

Q. Does Staff have any concerns about the rate design for general service rate E-32?

A. Yes. In the last rate case rate E-32 was completely redesigned. In that redesign the demand charge for customers under 20 kW was removed; however, the demand rate for customers above 20 kW was significantly increased. While that increase was made to move generation distribution capacity rates close to their cost, there were some lower load

factor customers who received rate increases significantly greater than the average increase due to the adoption of a much higher demand rate. Therefore, in this case, Staff would be concerned about raising demand rates significantly especially given that the rates adopted in the last rate case have only been in effect for a just over 16 months. Staff believes that the Commission should be cautious in raising demand rates significantly. Therefore, Staff recommends that the proposed demand rates for E-32 not be raised significantly over levels proposed by APS.

Q. Does Staff have any concerns about the structure of general service rate schedule E-32 generally?

A. Yes. General service rate schedule E-32 applies to general service customers with demands below 3,000 kW. About 96 percent of APS' general service customer base takes service on E-32. Currently this rate structure provides one set of rates for customers below 20 kW and a second set of rates for all other customers based in part on voltage levels. Therefore, in the rate design process for E-32, it can be difficult to tailor rate structures to different size customers with like usage characteristics. It is very common for utilities to develop general service rates for general service customers in differing size categories as opposed to one rate structure to cover the majority of general service customers. Staff believes that replacing E-32 with three separate tariffs for small general service, medium general service, and large general service categories could be beneficial for both APS and its ratepayers. Therefore, Staff recommends that in the next rate case filed with the Commission, APS propose to replace general service rate schedule E-32 with alternate general service schedules that divide E-32 usage into small, medium, and large categories or other appropriate division.

Q. Did Staff make any adjustments to the total dollar amount to be recovered through the System Benefits Charge?

A. Yes. Staff witness Mr. Jerry Anderson has testified that the total system benefit dollars to be recovered through rates is $49,191,690. Therefore, Staff recommends that the System Benefit Charge for all applicable APS rate schedules be set at $.001850 per kWh.[3]

SERVICE SCHEDULES

Schedule 1 -Terms and Conditions for Standard Offer and Direct Access Service

Q. What is Schedule 1?

A. Schedule 1 is a rate schedule that sets forth APS terms and conditions of service.

Q. Please briefly identify the nature of APS' proposed changes to Schedule 1.

A. APS has proposed making certain clarifying changes as well as changing the way the after-hours charge for other services is collected from customers.

Q. Did APS revise its proposed Schedule 1 filing originally provided in its application?

A. Yes. In response to Staff discovery, APS revised its originally filed proposal. A redlined copy and clean copy of APS' revisions to its original proposal is attached as Exhibit A.

Q. What types of changes did APS make in its revised proposal?

A. APS made clarifying changes including but not limited to: clarifying what types of services do not meet the definition of R14-2-203(D)(3), clarifying the manner in which specialized meter charges would be collected, correcting an outdated web address reference, and the addition of language related to master metering to comply with Commission rules.

[3] If the Commission chooses to increase the low income discounts on E-3 and E-4 as previously discussed, this rate may need to be adjusted.

Q. Please describe APS' proposal regarding the after-hours charge for other services.

A. The after-hours charge for other services is for work that is more specialized and beyond the scope of installing a meter, reading a meter, or turning the service on. Currently, the fee for this charge is $75.00 per trip. APS' proposal would change the way in which the charge is assessed to customers and result in a charge of $75.00 per crew person per hour.

Q. Please discuss your recommendation regarding the after-hours charge for other services.

A. Under APS' proposal to collect the charge on a per crew person per hour basis, customers would not be able to know ahead of time what they will be charged. In addition, it would be very difficult for customers to know whether the appropriate number of crew persons performed the work or whether the crew persons performed the work in a reasonable amount of time. Staff believes APS' proposal has the potential to create customer confusion. Therefore, Staff recommends that the after-hours charge on Schedule 1 for other services remain at $75.00 per trip.

Q. Please discuss your recommendation regarding the definitions section of the schedule.

A. APS should be required to include a definition for Multi-Unit Residential High-Rise Developments because there could be confusion about what constitutes a High-Rise Development. Therefore, Staff recommends that APS include a definition for Multi-Unit Residential High-Rise Developments on Schedule 1.

Q. Are APS' other proposed changes acceptable to Staff?

A. Yes. Staff has concluded that APS proposed changes to Schedule 1 are reasonable, subject to the modifications above.

Schedule 3 – Conditions Governing Extensions of Electric Distribution Lines and Services

Q. What is Schedule 3?

A. Schedule 3 is a service schedule that sets forth APS' line extension policy.

Q. Please briefly identify the nature of APS' proposed changes to Schedule 3.

A. APS has made changes to its line extension policy including: organizing the tariff by specific type of end-use development, changing the residential line extension allowance from a footage-based to a dollar-based allowance, removing the $25,000 economic feasibility study threshold for residential customers, and making certain changes regarding master metering provisions.

Q. Did APS revise its proposed Schedule 3 filing originally provided in its application?

A. Yes. In response to Staff discovery, APS revised its originally filed proposal. A clean copy of Schedule 3, outlining the changes from the current schedule with APS' revision to its original proposal, is attached as Exhibit B.

Q. What types of changes did APS make in its revised proposal?

A. APS made clarifying changes including but not limited to: the addition of a definitions section, the addition of new examples and narrative detailing how and when credits for allowances will be applied and calculated, and the addition of language related to master metering to comply with Commission rules.

Q. What type of costs are collected from ratepayers by Schedule 3?

A. Schedule 3 allows APS to collect the costs of installing distribution related facilities to the development of new homes and businesses within APS' service territory.

Q. Please discuss APS' proposal to move from a free footage-based allowance to a dollar-based allowance for Residential Single Family Homes.

A. Under the current schedule, a customer is given a free footage allowance of up to 1,000 feet. If the customer requires an extension for additional feet up to 2,000 feet or if the construction costs exceed $25,000, the customer provides an advance that is refundable for a period of five years as additional customers are served from the extension. For extensions that exceed 2,000 feet and are less than $25,000 APS would provide an extension based on a revenue test. For extensions that exceed 2,000 feet and are greater than $25,000, APS would provide an extension based upon an economic feasibility basis.

Under APS' proposal, the footage-based allowance would be eliminated and replaced with a dollar-based allowance of $5,000. If construction costs exceed the $5,000 allowance, customers would be required to provide an advance for the difference between the allowance and actual construction cost. The advance would continue to be refundable for a period of five years as additional customers are served from the line extension. In response to Staff discovery,[4] APS witness Mr. David Rumolo indicates that the proposed $5,000 allowance equates to a typical 500-foot overhead extension or a 600-700-foot underground extension.

Q. Does APS' proposal improve its ability to recover its distribution costs associated with new customer growth?

A. Yes. APS witness Mr. Rumolo (p. 36, lines 20-21) indicates that the construction cost for a 1000-foot line extension (overhead) currently provided to customers as a free allowance is in excess of $10,000. Therefore, APS' proposed policy would result in APS recovering

[4] APS response to EAA-17-6.

approximately $5,000 more per residential single family home than under their current free-footage allowance for a 1000-foot extension.

Q. Are there other benefits in terms of cost recovery to APS in moving from a footage-based allowance to a dollar-based allowance?

A. Yes. Footage-based allowances do not account for increases in construction costs that may occur through time. In addition, footage-based allowances do not reflect the increase in costs associated with construction in more difficult terrains.

Q. APS has reorganized Schedule 3 by specific type of end-use development. Please identify APS' proposed allowances for other types of residential developments.

- Residential Homebuilder Subdivisions – A $5,000 per lot allowance would be credited against the total construction cost which may include backbone system costs minus streetlight and system improvement costs[5] for a period up to 5 years. Construction costs in excess of the allowance would be paid by the applicant as a non-refundable contribution in aid of construction.

- Residential Custom Home "Lot Sale" Developments – A $5,000 per completed home allowance would be credited against the construction costs minus street light and system improvement costs. Any additional construction costs would be paid by the applicant as a non-refundable contribution in aid of construction.

- Master Planned Community Developments – A $1,000 per lot allowance may be credited against backbone infrastructure costs minus streetlight and system

[5] System Improvement Costs means the costs of system additions over and above what is required to serve the customer, where such additions provide additional capacity for other customers.

improvement costs, and a $4,000 allowance will be credited against subdivision costs minus streetlight and system improvement costs. Any additional costs will be paid by the applicant as a non-refundable contribution in aid of construction.

- Residential Multi-Family Developments such as apartments, condominiums and townhouses – A $500 per completed unit allowance may be credited against the total construction cost including backbone infrastructure cost minus streetlight and system improvement costs. Any additional costs will be paid by the applicant as a non-refundable contribution in aid of construction.

Q. Please identify the proposed allowance for Residential High-Rise and Mixed Use Residential Developments.

A. The allowance is based on economic feasibility. APS determines the economic feasibility by calculating the estimated annual revenue based on APS' then currently effective rate for distribution service (excluding taxes, regulatory assessment, and other adjustments) less the cost of service. If the difference provides an adequate rate of return on the investment made by APS to serve the customers and the development, then the extension is deemed economically feasible. In response to Staff discovery,[6] APS has indicated that "an adequate rate of return" refers to the class rate of return approved in the most recent rate case.

Q. Please describe the proposed policy for non-residential developments.

A. The proposed criteria for non-residential developments has not changed. APS' proposed policy includes a provision for non-residential extensions based upon revenue-based criteria and an economic feasibility basis. Under the revenue based criteria, the extension

[6] APS response to EAA 17-1.

would be free where the estimated annual revenue based on APS' then currently effective rate for distribution service (excluding taxes, regulatory assessment, and other adjustments) multiplied by six is equal to or greater than the total construction costs less nonrefundable customer contributions. The economic feasibility policy for non-residential developments is the same as the economic feasibility policy for Residential High-Rise and Mixed Use Residential Developments described above.

Q. Do you have any comments or recommendations about the section titled Residential Custom "Lot Sale" Developments?

A. Yes. Under this policy, the applicant would be required to pay a refundable advance for backbone infrastructure. When completed, and if approved by APS, the $5,000 allowance would be credited against the construction cost minus street lighting and system improvements. Staff believes that the "construction cost" refers to the "backbone infrastructure cost." Staff recommends that APS should add clarifying language to Schedule 3 to specify that the "construction cost" refers to the "backbone infrastructure cost."

Q. Do you have any comments or recommendations about the section titled Master Planned Community Developments and Residential Multi-Family Developments?

A. Yes. As currently worded, the applicable per lot and per unit allowance "may" be credited against the construction costs. In order to assure that credits will be issued to the applicant, Staff recommends that under sections titled Master Planned Community Developments and Residential Multi-Family Developments of Schedule 3, APS clarify that allowances will be credited to the applicant.

Q. Do you have any recommendations about the definition section of Schedule 3?

A. Yes. According to APS, the current definition for "Residential Homebuilder Subdivision" was derived from the definition for "Subdivision" in A.R.S. § 32-2101(55)(a) of Arizona Real Estate law which refers to a "Subdivision" as consisting of six or more lots, parcels, or fractional interest. However, under Commission rule R14-2-201(34), a "Residential Subdivision Development" refers to a tract of land which has been divided into four or more contiguous lots. Therefore, Staff recommends that APS amend its definition for "Residential Homebuilder Subdivision" on Schedule 3 to be consistent with R14-2-201(34). Staff also recommends that APS alphabetize the definitions included on Schedule 3.

Q. Do you have any recommendations about the timing for field audits and the five-year timeframe in which refundable advances can be refunded to applicants?

A. Yes. As the schedule is currently worded, it is not clear that the 18-month timeframe for field audits, and the five-year timeframe in which refundable advances can be refunded to applicants, applies to each individual development type. Therefore, Staff recommends that APS add language to each section of Schedule 3 clarifying the applicable timeframes for field audits and refundable advances.

Q. What else does Staff recommend in regard to Schedule 3?

A. Staff recommends that APS should file a revised Schedule 3 including Staff's recommendations above in its rebuttal testimony. In its rebuttal testimony, APS should provide a copy of its proposed Schedule 3 redlined against the current version attached to my testimony as Exhibit B.

HOOK-UP FEES

Q. Please explain why Staff is addressing the issue of hook-up fees.

A. On March 28, 2006, Commissioner Mundell issued a letter in this docket requesting that the parties in this proceeding provide an analysis of the efficacy of using hook-up fees to help fund APS' capital expenditures so that existing customers are not continually subject to rate increases.

Q. Is Staff recommending the adoption of hook-up fees for APS at this time?

A. No. My testimony raises certain issues that should be addressed prior to the adoption of hook-up fees for APS.

Q. Could you please briefly describe the purpose of a hook-up fee?

A. Yes. Hook-up fees have been generally adopted by the Commission in the water and wastewater industries as a way of providing accelerated recovery to a utility for the installation of infrastructure necessary to serve new customers. An additional benefit of adopting hook-up fees is that existing customers are less likely to subsidize the capital costs required to serve new growth. Since funds collected from hook-up fees are treated as contributions for ratemaking purposes, these funds directly offset rate base which can also reduce the need for a utility to file for future rate relief.

Q. Has Staff researched the adoption of hook-up fees for utilities in other jurisdictions?

A. Yes. Staff surveyed Commissions in other States and found that where they existed, hook-up fees were more commonly adopted for water and wastewater utilities. However, at least one jurisdiction responding to Staff's survey (Maine) adopted a policy where all new customers pay 100 percent of the distribution and transmission costs that the electric utility incurs to serve that specific customer.

Q. Do any of Arizona's electric utilities currently have hook-up fees in place?

A. Yes. Staff is aware of two electric utilities in Arizona that utilize hook-up fees. Dixie Escalante Rural Electric Association which serves a small portion of the northeastern part of Arizona has a Commission-approved impact fee that imposes a $750 per residential hook-up for installed capacity of over 20 kW plus a $20 connect fee and $60 per kW based on the maximum installed capacity for Commercial, Irrigation, and General service plus a $20 connect fee.[7]

In addition, Wellton-Mohawk Irrigation and Drainage District[8] ("Wellton"), which provides electric service to a small portion of the southwestern part of Arizona, recently adopted a $750 hook-up fee for new residential facilities plus a $29 connect fee. Wellton has indicated that hook-up fees for non-residential facilities are considered on a case-by-case basis.

Q. What types of costs could be included in an electric hook-up fee?

A. Capital expenditures associated with incremental distribution, transmission, and generation capacity could be attributed to new growth and included in a hook-up fee.

Q. Please comment on possible options for the design of a hook-up fee.

A. Hook-up fees should be designed with a goal of equitably apportioning the cost of constructing new facilities required to meet customer growth and can be designed in a variety of ways.

One method commonly used in the water industry takes the full cost of additional plant or facilities and divides the cost by the total number of estimated new and existing service

[7] Connect fees generally cover the administrative costs attributable to the establishment of a new customer.
[8] Wellton is not a Commission jurisdictional utility.

connections that will be served by that plant. However, this method fails to account for the fact that new customers will commence paying usage rates that also recover the costs incurred to serve an average customer, potentially creating a double payment burden on new customers.

A second method that could be adopted would involve marginal cost studies to isolate the difference between the full incremental costs associated with adding additional generation capacity, transmission, distribution facilities, and related expenses to serve a typical new customer within each rate class. Once the incremental costs are determined, the average imbedded costs already included in base rates should be subtracted from the incremental cost; the results should then be divided by the total number of estimated new connections. This method takes into account the fact that new customers would be paying a hook-up fee but also would commence paying for similar costs already embedded in base rates. This approach puts current and new customers on an equal ground and further reduces any subsidization between existing and new customers.

Q. Please provide some of the questions Staff believes are appropriate to explore prior to designing a hook-up fee.

A. Some of the questions that should be considered in the design of a hook-up fee are provided below.

- Should generation capacity be included in a hook-up fee given the complexities associated with determining and designing a rate to recover the cost associated with generation capacity?
- What type of generation unit or related index should be utilized as a proxy for calculating marginal cost for generation capacity?

- Should a study of marginal costs be required as a means of calculating a unit of demand, energy, and distribution including customer-related cost?
- Should operation and maintenance expenses be included as well as capital expenditures?
- What is the appropriate customer growth or customer decline assumption?
- Over what timeframe should costs be accrued for purposes of setting a rate?
- How often should the rate be updated so that the rate accurately reflects current marginal cost and customer growth rates?
- How should the cost be allocated to different customer classes and collected from individual customers?
- What is the impact on direct access customers, where a customer chooses to receive generation supply from a competitive electric service provider?
- What are the economic impacts of adopting hook-up fees within APS' service territory?
- If hook-up fees are adopted for APS, would there be any impacts for natural gas suppliers within APS service territory?

Q. Please provide an example of a hook-up fee based on actual distribution and transmission investment in 2005.

A. In response to Staff discovery,[9] APS has provided actual costs associated with historical transmission and distribution capital expenditures from 1997-2005. To provide a very general estimate of a system wide hook-up fee, if the Commission were to adopt an approach of setting a rate for a transmission and distribution hook-up fee, where the total transmission and distribution costs were divided by the total number of new meter sets, the calculation would result in a hook-up fee of approximately $5,900. It should be noted,

[9] APS response to EAA 4-12 (APS 10390).

however, that APS has indicated that a small percentage of capital expenditures such as replacements and upgrades not directly attributable to growth are included in the capital expenditure figures provided to Staff.[10] This will have the effect of inflating the calculated charge slightly.

If the Commission were to adopt a method of setting a hook-up fee for transmission and distribution based on the difference between average imbedded transmission and distribution cost in rate base and actual incremental cost associated with transmission and distribution divided by the number of new meter sets in 2005, the calculation would result in a hook-up fee of about $3,100.

Q. Would it be possible to implement both a hook-up fee and a line extension policy?

A. Yes. A line extension policy would cover costs in excess of the hook-up fee and cover costs associated with more specialized capital-intensive distribution construction requirements. However, the structure of APS' line extension policy (Schedule 3) would have to be changed because it would be inconsistent to adopt a hook-up fee which includes a cost for new distribution investment if a utility's line extension policy includes a free allowance. If hook-up fees are adopted for APS, the proposed $5,000 allowance for Single Family Homes, Residential Homebuilder Subdivisions, and other residential allowances on Schedule 3 should be removed and changes should be made to account for specialized distribution-related costs in excess of that included in the hook-up fee.

One approach the Commission may consider to improve cost recovery associated with distribution cost in future APS rate cases, would be to remove provisions for free allowances on Schedule 3 altogether. This approach could be the first step in the direction

[10] APS indicates currently it does not break down its transmission and distribution capital expenditures by new growth or by rate class.

of assigning new distribution costs to those customers that make it necessary to build new distribution facilities and could then be followed by the implementation of hook-up fees which could also collect the costs associated with transmission and/or generation.

Q. Is Staff recommending the adoption of hook-up fees for APS at this time?

A. No. As previously discussed, Staff has numerous unanswered questions which should be addressed if the Commission chooses to pursue adopting hook-up fees for APS. In addition, Staff has not had the benefit of reviewing a specific proposal. Recently Commissioner Mayes requested that hook-up fees also be evaluated in the context of the pending UNS Gas rate case.[11] Staff agrees with the Residential Utility Consumer Office ("RUCO") witness Ms. Marylee Diaz Cortez in her belief that that if the Commission chooses to pursue hook-up fees for electric and gas utilities, Staff and the Commission would benefit from input from all interested and affected parties regarding the pros and cons of adopting hook-up fees as well as the design of those fees. Therefore, if the Commission chooses to pursue hook-up fees for electric and gas utilities, Staff recommends that the Commission open a generic docket where parties can provide feedback and the Commission can evaluate the adoption of hook-up fees for the energy industry.

DEMAND RESPONSE AND LOAD MANAGEMENT

Q. Staff's draft Demand-side Management ("DSM") Rules include definitions for demand response and load management. Please describe the difference between demand response and load management.

A. Demand-response programs are programs and pricing mechanisms designed to provide incentives for customers to reduce their load in response to prices, market conditions, or

[11] Docket No. G-04204A-06-0463

threats to system reliability. Demand response programs may include dynamic pricing/tariffs, price responsive demand bidding, contractually obligated or voluntary curtailment, and direct load control or cycling by the customer. Time-based demand response such as time-of-use, critical-peak pricing, and real-time pricing are also demand-response programs.

Load management refers to deliberate actions initiated by a utility to reduce peak demands or to improve system-operating efficiency. Examples of load management include: direct control of demands through utility-initiated interruption or cycling, thermal storage, and education to encourage customers to shift loads.

The main difference between demand response and load management is that demand response refers to deliberate actions taken by the customer to reduce their load where load management refers to utility-initiated activities.

Q. Please discuss the benefits of adopting demand-response or load-management programs.

A. Demand response can result in savings of variable supply costs during times when wholesale prices and demand are high, displacing the need to build additional capacity related infrastructure such as generation, transmission, and distribution, and improving system reliability by reducing demand when facilities such as a generator or transmission line fail. In load pockets such as the Phoenix metropolitan area, demand-response and load-management programs can be particularly beneficial especially during periods of high demand or when facilities fail.

Q. What type of demand-response programs are currently offered by other Arizona utilities?

A. It is not uncommon for utilities in the state to offer time-of-use rates and interruptible rates. For instance, Tucson Electric Power and Trico Electric Cooperative are just two utilities that offer various time-of use rates, and interruptible rates. In addition, Salt River Project ("SRP") currently offers time-of-use rates, interruptible riders, and a critical-peak pricing rate for its general service class. Currently, there are no customers participating in SRP's critical-peak pricing pilot. SRP believes that this is due to the fact that the program did not provide enough economic incentive given the fact that all of SRP's general service customers are currently on time-of-use rates and some also have interruptible contracts. Therefore, SRP believes the benefits of load shifting may already be realized for SRP's general service class. However, SRP is currently considering the merits of offering critical-peak pricing for other customer classes.[12]

Q. What type of demand-response programs are currently being provided by APS?

A. APS currently offers several time-of-use rates for its residential customers, one time-of-use rate for its general-service class, and time-of-use and time-of-week options for its water pumping customers. In addition, APS provides an "APS Power Partners" program, in which participating business customers voluntarily reduce their load when temperatures exceed 110 degrees in the Phoenix area. While Staff believes that these programs are valuable in reducing peak demand or shifting load, Staff believes it is important to adopt a more extensive and more diverse portfolio of demand-response or load-management programs. Given the fact that Phoenix is located within a load pocket, and according to APS estimates[13] customer growth is not expected to decline significantly for the next

[12] Salt River Project Agricultural Improvement and Power District, Management Report for Time-Based Metering and Communications: Section 111(D)(14) of the Public Utility Regulatory Policies Act (PURPA), August 11, 2006, 16.
[13] APS Response to EAA-4-16 (APS09172).

several years, demand-response and load-management programs may be beneficial for APS and its ratepayers.

Q. Commission Decision No. 67744 directed APS to study rate designs that promote energy efficiency, conservation, and reduce peak demand. Did APS provide an analysis of demand-response programs as a way of reducing peak demand?

A. Yes. At page 37 of DJR_9, APS witness Mr. Rumolo provides an analysis of critical-peak pricing, real-time pricing, and demand-bidding programs. Mr. Rumolo's analysis identifies advantages and disadvantages of each and provides results of demand-response programs in other jurisdictions. Mr. Rumolo's analysis results in a conclusion that due to unknown participation levels and implementation issues associated with cost, APS will continue to monitor critical-peak pricing and demand bidding programs to assess designs, program best practices, customer participation, and load impacts. Mr. Rumolo also concludes that APS will further assess program implementation costs, especially communication infrastructure, data handling, and billing systems to better assess costs and benefits.

Q. Would APS incur additional costs associated with the implementation of demand-response or load-management programs?

A. Yes. However, the magnitude of the cost depends on the size of the deployment and the design of the program. Some of the technologies required would include meters that measure and store interval load data, and provide communications links between the customer and the utility. In addition, equipment that provides direct load control initiated by either the customer or the utility may be required. In addition to metering and communication upgrades, upgrades to the billing system and metering information system may also be required.

It should be noted, however, that where advanced metering technologies are adopted, they can provide benefits to the utility beyond the implementation of demand-response or load-management programs. For instance, advanced metering systems can help the utility to reduce operational costs associated with meter reading, managing power outages, and detecting energy diversion. In addition, the utility benefits from improved load data that it can use for its load-forecasting and research efforts and is often able to provide enhanced customer service.

Q. Did Commission Decision No. 67744 address the potential for cost recovery for demand-side response programs?

A. Yes. Paragraph 49 in the settlement agreement quoted below indicates that APS may request Commission approval for demand-side response program costs that exceed the initial $48 million in DSM expenditures over the three-year period.

> 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.

Q. Please comment on Mr. Rumolo's conclusions.

A. While Staff agrees that there may be several unknowns about overall program performance, the benefits of a properly designed demand-response and/or load-management program may outweigh the costs. In order to effectively evaluate the impact of demand-response and load-management programs for APS, cost benefit analyses should be completed.

Q. Do the draft DSM rules address cost effectiveness for demand-response and load-management programs?

A. Yes. Under the draft DSM rules, cost-effectiveness for DSM programs, including demand response and load management, shall be determined by the Societal Cost Test.

Q. Does Staff agree with the RUCO witness Ms. Diaz Cortez's recommendation to establish a demand-response task force?

A. Staff believes establishing a forum to explore issues associated with demand response opportunities may be beneficial. Specifically, issues such as which programs will be the most beneficial for APS' system and its ratepayers, which customer segments will be able to respond to demand response and/or load management programs, what kinds of system enhancements or upgrades would be required, and how to measure costs and benefits of a particular program within the construct of the Societal Cost test are all topics that could be addressed. Therefore, Staff recommends that APS establish a forum to explore issues associated with demand-response and load-management opportunities for its service territory.

Q. What does Staff recommend regarding demand-response and load-management programs?

A. Staff recommends that APS conduct a study that identifies which types of demand-response and load-management programs would be most beneficial to APS' system. In the study, APS should demonstrate why certain programs are more beneficial than others and identify which customer segments would be most likely to respond to such programs. The study should rely on a cost-benefit analysis based on the Societal Cost Test and be filed with the Commission within eight months of approval of a decision in this matter. In addition, APS should be required to file for Commission approval of one or more cost-

effective demand-response or load-management programs that APS believes would be most beneficial to its system and its ratepayers, and to file it concurrently with the filing the study referred to above.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please provide a summary of your recommendations.

A.
1. Staff recommends higher than average increases for rate schedules E-34 and E-35 based on the fact that these categories are under performing relative to the rest of the general service class and the system-average rate of return.
2. Staff recommends that the cost-of-service category E-32 (1,000 or greater kW) receive a greater increase than E-32 cost-of-service categories (0-20 kW), (21-100 kW), (101-400 kW), and (401-999 kW).
3. Staff recommends that rate schedule E-20 receive a much smaller than average increase due to the fact that its return is much greater than the system average and exceeds the returns for the other rate categories in the cost-of-service study.
4. Staff recommends that APS provide a 12-month interim period for customer transition so that residential customers on E-10 and EC-1 will have additional time to fully evaluate their alternative rate options. Staff also recommends that APS continue customer outreach efforts to educate consumers about their rate options during the 12-month interim period.
5. Staff recommends that E-10 and EC-1 not be cancelled until the end of the 12-month interim period, which should provide customers with adequate time to consider alternative rate options.
6. Staff recommends that APS provide customers on E-21, E-22, E-23, and E-24 a six-month interim period for customer transition so that customers would be provided adequate time to consider other rate options and allow APS time to switch out meters

where required. Staff also recommends that APS propose an interim rate increase to apply during the interim period for rates E-21, E-22, E-23, and E-24 that is greater than the average increase for the general service class.

7. Staff recommends that E-21, E-22, E-23, and E-24 not be cancelled until the end of the six-month interim period, which should provide customers with time to consider alternative rate options.
8. Staff recommends that rate designs for residential rates ET-2 and ECT-2 remain revenue neutral when compared to rates adopted for ET-1 and ECT-2 respectively.
9. Staff recommends that the proposed demand rates for E-32 not be raised significantly over levels proposed by APS.
10. Staff recommends that in the next rate case filed with the Commission, APS propose to replace general service rate schedule E-32 with alternate general service schedules that divide E-32 usage into small, medium, and large categories or other appropriate division.
11. Staff recommends that the System Benefit Charge for all applicable APS rate schedules be set at $.001850 per kWh.
12. Staff recommends that the after-hours charge on Schedule 1 for other services remain at $75.00 per trip.
13. Staff recommends that APS include a definition for Multi-Unit Residential High-Rise Developments on Schedule 1.
14. Staff recommends that APS should add clarifying language to Schedule 3 to specify that the "construction cost" refers to the "backbone infrastructure cost."
15. Staff recommends that under sections titled Master Planned Community Developments and Residential Multi-Family Developments of Schedule 3, APS clarify that allowances will be credited to the applicant.

16. Staff recommends that APS amend its definition for "Residential Homebuilder Subdivision" on Schedule 3 to be consistent with R14-2-201(34). Staff also recommends that APS alphabetize the definitions included on Schedule 3.
17. Staff recommends that APS add language to each section of Schedule 3 clarifying the applicable timeframes for field audits and refundable advances.
18. Staff recommends that APS should file a revised Schedule 3 including Staff's recommendations above in its rebuttal testimony. In its rebuttal testimony, APS should provide a copy of its proposed Schedule 3 redlined against the current version attached to my testimony as Exhibit B
19. Staff recommends that the Commission open a generic docket where parties can provide feedback and the Commission can evaluate the adoption of hook-up fees for the energy industry.
20. Staff recommends that APS establish a forum to explore issues associated with demand-response and load-management opportunities for its service territory.
21. Staff recommends that APS conduct a study that identifies which types of demand-response and load-management programs would be most beneficial to APS' system. In the study, APS should demonstrate why certain programs are more beneficial than others and identify which customer segments would be most likely to respond to such programs. The study should rely on a cost-benefit analysis based on the Societal Cost Test and be filed with the Commission within eight months of approval of a decision in this matter. In addition, APS should be required to file for Commission approval of one or more cost-effective demand-response or load-management programs that APS believes would be most beneficial to its system and its ratepayers, and to file it concurrently with the filing the study referred to above.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EAA-1

Summary of Cost of Service Results with Interclass Returns

Summary of Staff Cost of Service Results
4-CP and Average and 4-CP Allocation for Production Demand
Arizona Public Service **EAA-1**
E-01345A-05-0816

	4-CP and Average		4-CP	
	Rate of Return	Rate of Return Index	Rate of Return	Rate of Return Index
Residential				
E-10 (frozen)	4.04%	0.77	4.12%	0.79
E-12	5.94%	1.14	5.70%	1.09
EC-1 (frozen)	3.05%	0.58	3.12%	0.6
ET-1	3.58%	0.69	3.20%	0.61
ECT-1	2.62%	0.5	2.52%	0.48
Total Residential	4.25%	0.81	3.99%	0.76
General Service				
E-20	9.82%	1.88	10.59%	2.03
E-30, E-32 (0-20 kW)	7.00%	1.34	5.56%	1.06
E-32 (21-100 kW)	7.76%	1.49	7.19%	1.38
E-32 (101-400 kW)	8.65%	1.66	9.21%	1.76
E-32 (401-999 kW)	7.76%	1.48	9.56%	1.83
E-32 (1,000 + kW)	-2.30%	-0.44	3.12%	0.60
E-34	-2.52%	-0.48	3.79%	0.73
E-35	-0.22%	-0.04	2.54%	0.49
Total General Service	6.51%	1.25	6.79%	1.3
E-38, E-221 (Water Pumping)	8.30%	1.59	13.58%	2.6
Street Lighting	2.18%	0.42	3.32%	0.64
Dusk to Dawn	5.98%	1.15	6.69%	1.28
Total Retail	5.23%	1.00	5.23%	1.00

EAA-2

Summary of Staff Proposed Residential Rates With Customer Transition

Summary of Staff Proposed Residential Rates
Includes Customer Transition
Arizona Public Service
E-01345A-05-0816

Rate Schedule	Season	Block	Present Rate	Proposed Rate	Difference $	Difference %
E-10						
Interim Rate	Summer	Basic Service Charge	$0.253	$0.253	$0.000	0.00%
		First 400 kWh	$0.06929	$0.07988	$0.01059	15.28%
		Next 400 kWh	$0.09490	$0.10678	$0.01188	12.52%
		All additional kWh	$0.09760	$0.11354	$0.01594	16.33%
	Winter	Basic Service Charge	$0.253	$0.253	$0.000	0.00%
		All kWh	$0.07601	$0.08246	$0.00645	8.48%
E-12						
	Summer	Basic Service Charge	$0.253	$0.253	$0.000	0.00%
		First 400 kWh	$0.07570	$0.08177	$0.00607	8.01%
		Next 400 kWh	$0.10556	$0.11557	$0.01001	9.48%
		All additional kWh	$0.12314	$0.13552	$0.01238	10.05%
	Winter	Basic Service Charge	$0.253	$0.253	$0.000	0.00%
		All kWh	$0.07361	$0.08001	$0.00640	8.69%
EC-1						
Interim Rate	Summer	Basic Service Charge	$0.329	$0.329	$0.000	0.00%
		All kW	$10.00	$11.02	$1.02	10.23%
		All kWh	$0.03943	$0.04538	$0.00595	15.08%
	Winter	Basic Service Charge	$0.329	$0.329	$0.000	0.00%
		All kW	$7.10	$8.13	$1.03	14.54%
		All kWh	$0.02978	$0.03124	$0.00146	4.90%

Summary of Staff Proposed Residential Rates
Includes Customer Transition
Arizona Public Service
E-01345A-05-0816

Rate Schedule	Season	Block	Present Rate	Proposed Rate	Difference $	Difference %
ET-1						
	Summer	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kWh	$0.13310	$0.15008	$0.01698	12.76%
		All Off-Peak kWh	$0.04299	$0.04794	$0.00495	11.51%
		Basic Service Charge	$0.493	$0.493	$0.000	0.00%
	Winter	All On-Peak kWh	$0.10918	$0.12201	$0.01283	11.75%
		All Off-Peak kWh	$0.04167	$0.04638	$0.00471	11.30%
ECT-1R						
	Summer	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kW	$11.81	$12.14	$0.33	2.79%
		All On-Peak kWh	$0.04765	$0.05836	$0.01071	22.47%
		All Off-Peak kWh	$0.02672	$0.03227	$0.00555	20.77%
	Winter	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kW	$8.11	$8.31	$0.20	2.47%
		All On-Peak kWh	$0.03641	$0.04445	$0.00804	22.08%
		All Off-Peak kWh	$0.02570	$0.03103	$0.00533	20.74%
ET-2						
	Summer	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kWh	$0.18200	$0.20522	$0.02322	12.76%
		All Off-Peak kWh	$0.04519	$0.05039	$0.00520	11.51%
		Basic Service Charge	$0.493	$0.493	$0.000	0.00%
	Winter	All On-Peak kWh	$0.08703	$0.09726	$0.01023	11.75%
		All Off-Peak kWh	$0.05783	$0.06437	$0.00654	11.31%

Summary of Staff Proposed Residential Rates
Includes Customer Transition
Arizona Public Service
E-01345A-05-0816

Rate Schedule	Season	Block	Present Rate	Proposed Rate	Difference $	Difference %
ECT-2						
	Summer	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kW	$11.81	$12.14	$0.33	2.79%
		All On-Peak kWh	$0.05690	$0.06969	$0.01279	22.48%
		All Off-Peak kWh	$0.02792	$0.03372	$0.00580	20.77%
	Winter	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kW	$8.11	$8.31	$0.20	2.47%
		All On-Peak kWh	$0.03730	$0.04554	$0.00824	22.09%
		All Off-Peak kWh	$0.02733	$0.03300	$0.00567	20.75%

EAA-3

Summary of Residential Rates for Informational Scenario #2 No Customer Transition

Summary of Residential Rates
No Customer Transition
Arizona Public Service
E-01345A-05-0816

Rate Schedule	Season	Block	Present Rate	Proposed Rate	Difference $	Difference %
E-10						
	Summer	Basic Service Charge	$0.253	$0.253	$0.00	0.00%
		First 400 kWh	$0.06929	$0.07988	$0.01059	15.28%
		Next 400 kWh	$0.09490	$0.10678	$0.01188	12.52%
		All additional kWh	$0.09760	$0.11354	$0.01594	16.33%
	Winter	Basic Service Charge	$0.253	$0.253	$0.00	0.00%
		All kWh	$0.07601	$0.08246	$0.00645	8.48%
E-12						
	Summer	Basic Service Charge	$0.253	$0.253	$0.000	0.00%
		First 400 kWh	$0.07570	$0.08326	$0.00756	9.99%
		Next 400 kWh	$0.10556	$0.11795	$0.01239	11.74%
		All additional kWh	$0.12314	$0.13932	$0.01618	13.14%
	Winter	Basic Service Charge	$0.253	$0.253	$0.000	0.00%
		All kWh	$0.07361	$0.08063	$0.00702	9.54%
EC-1						
	Summer	Basic Service Charge	$0.329	$0.329	$0.000	0.00%
		All kW	$10.00	$11.02	$1.02	10.23%
		All kWh	$0.03943	$0.04538	$0.00595	15.08%
	Winter	Basic Service Charge	$0.329	$0.329	$0.00	0.00%
		All kW	$7.10	$8.13	$1.03	14.54%
		All kWh	$0.02978	$0.03124	$0.00146	4.90%

Summary of Residential Rates
No Customer Transition
Arizona Public Service
E-01345A-05-0816

Rate Schedule	Season	Block	Present Rate	Proposed Rate	Difference $	Difference %
ET-1						
	Summer	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kWh	$0.13310	$0.15007	$0.01697	12.75%
		All Off-Peak kWh	$0.04299	$0.04793	$0.00494	11.49%
	Winter	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kWh	$0.10918	$0.12200	$0.01282	11.74%
		All Off-Peak kWh	$0.04167	$0.04637	$0.00470	11.28%
ECT-1R						
	Summer	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kW	$11.81	$12.15	$0.34	2.86%
		All On-Peak kWh	$0.04765	$0.05877	$0.01112	23.33%
		All Off-Peak kWh	$0.02672	$0.03223	$0.00551	20.62%
	Winter	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kW	$8.11	$8.32	$0.21	2.58%
		All On-Peak kWh	$0.03641	$0.04539	$0.00898	24.66%
		All Off-Peak kWh	$0.02570	$0.03103	$0.00533	20.74%
ET-2						
	Summer	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kWh	$0.18200	$0.20520	$0.02320	12.75%
		All Off-Peak kWh	$0.04519	$0.05038	$0.00519	11.48%
		Basic Service Charge	$0.493	$0.493	$0.000	0.00%
	Winter	All On-Peak kWh	$0.08703	$0.09725	$0.01022	11.74%
		All Off-Peak kWh	$0.05783	$0.06435	$0.00652	11.28%

Summary of Residential Rates
No Customer Transition
Arizona Public Service
E-01345A-05-0816

Rate Schedule	Season	Block	Present Rate	Proposed Rate	Difference $	Difference %
ECT-2						
	Summer	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kW	$11.81	$12.15	$0.34	2.86%
		All On-Peak kWh	$0.05690	$0.07017	$0.01327	23.32%
		All Off-Peak kWh	$0.02792	$0.03368	$0.00576	20.63%
	Winter	Basic Service Charge	$0.493	$0.493	$0.000	0.00%
		All On-Peak kW	$8.11	$8.32	$0.21	2.58%
		All On-Peak kWh	$0.03730	$0.04650	$0.00920	24.66%
		All Off-Peak kWh	$0.02733	$0.03300	$0.00567	20.75%

EAA-4

E-12 Customer Bill Components
Peak Summer Month 2005

Staff Proposed E-12
Includes Customer Transition
Summary of Customer Bill Components
Arizona Public Service
E-01345A-05-0816

EAA-4

Peak Summer Month July 2005

Average Use	981
Median Use	818

Average Use July 2005		Present Base Rate	Proposed Base Rate	Increase $	Increase %
Present Base Rate		$102.38	$111.05	$8.67	
Environmental Portfolio Surcharge Adjustor [1]	0.001392	$0.35	$0.56	$0.21	
Competition Rules Compliance Charge	0.000338	$0.33	$0.33	$0.00	
Power Supply Adjustor	0.004000	$3.92	$3.92	$0.00	
Interim Adjustor Rate	0.007000	$6.87	$6.87	$0.00	
Surcharge 1	0.000554	$0.54	$0.54	$0.00	
Surcharge 2 [2]	0.001029	$1.01	$1.01	$0.00	
DSM Adjustor [3]	0.000000	$0.00	$0.00	$0.00	
Total Bill		$115.41	$124.29	$8.88	7.69%

Median Use July 2005		Present Base Rate	Proposed Base Rate	Increase $	Increase %
Present Base Rate		$82.31	$88.96	$6.65	
Environmental Portfolio Surcharge Adjustor	0.001392	$0.35	$0.56	$0.21	
Competition Rules Compliance Charge	0.000338	$0.28	$0.28	$0.00	
Power Supply Adjustor	0.004000	$3.27	$3.27	$0.00	
Interim Adjustor Rate	0.007000	$5.73	$5.73	$0.00	
Surcharge 1	0.000554	$0.45	$0.45	$0.00	
Surcharge 2	0.001029	$0.84	$0.84	$0.00	
DSM Adjustor	0.000000	$0.00	$0.00	$0.00	
Total Bill		$93.23	$100.09	$6.86	7.36%

1) Proposed rate per the testimony of Staff witness Barbara Keene.

2) Proposed rate per the testimony of Staff witness Barbara Keene.

3) DSM Adjustor will not go into effect until APS spends more than $10 million in DSM in a calendar year.

EAA-5

Typical Bill Analysis Staff Recommended Rates With Customer Transition

Arizona Public Service Company

Typical Residential Bill Analysis **EAA-5**

E-10 to E-10 Interim Rate Based on No Transition Rate Summer (May - October)

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	942	87.13	98.38	11.25	12.91%
Median	727	66.34	74.46	8.12	12.24%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	200	21.45	23.57	2.12	9.88%
	250	24.91	27.56	2.65	10.64%
	300	28.38	31.55	3.17	11.17%
	350	31.84	35.55	3.71	11.65%
	400	35.31	39.54	4.23	11.98%
	450	40.05	44.88	4.83	12.06%
	500	44.80	50.22	5.42	12.10%
	550	49.54	55.56	6.02	12.15%
	600	54.29	60.90	6.61	12.18%
	650	59.03	66.24	7.21	12.21%
	700	63.78	71.58	7.80	12.23%
	750	68.52	76.92	8.40	12.26%
	800	73.27	82.26	8.99	12.27%
	850	78.15	87.93	9.78	12.51%
	900	83.03	93.61	10.58	12.74%
	950	87.91	99.29	11.38	12.95%
	1,000	92.79	104.96	12.17	13.12%
	1,100	102.55	116.32	13.77	13.43%
	1,200	112.31	127.67	15.36	13.68%
	1,300	122.07	139.03	16.96	13.89%
	1,400	131.83	150.38	18.55	14.07%
	1,500	141.59	161.73	20.14	14.22%
	1,600	151.35	173.09	21.74	14.36%
	1,700	161.11	184.44	23.33	14.48%
	1,800	170.87	195.80	24.93	14.59%
	1,900	180.63	207.15	26.52	14.68%
	2,000	190.39	218.50	28.11	14.76%
	2,200	209.91	241.21	31.30	14.91%
	2,400	229.43	263.92	34.49	15.03%
	2,600	248.95	286.63	37.68	15.14%
	2,800	268.47	309.34	40.87	15.22%
	3,000	287.99	332.04	44.05	15.30%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis **EAA-5**

E-10 to E-10 Interim Rate Based on No Transition Rate Winter (November-April)

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	705	61.18	65.72	4.54	7.42%
Median	574	51.22	54.92	3.70	7.22%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	200	22.79	24.08	1.29	5.66%
	250	26.59	28.20	1.61	6.05%
	300	30.39	32.33	1.94	6.38%
	350	34.19	36.45	2.26	6.61%
	400	37.99	40.57	2.58	6.79%
	450	41.79	44.70	2.91	6.96%
	500	45.60	48.82	3.22	7.06%
	550	49.40	52.94	3.54	7.17%
	600	53.20	57.06	3.86	7.26%
	650	57.00	61.19	4.19	7.35%
	700	60.80	65.31	4.51	7.42%
	750	64.60	69.43	4.83	7.48%
	800	68.40	73.55	5.15	7.53%
	850	72.20	77.68	5.48	7.59%
	900	76.00	81.80	5.80	7.63%
	950	79.80	85.92	6.12	7.67%
	1,000	83.60	90.05	6.45	7.72%
	1,100	91.20	98.29	7.09	7.77%
	1,200	98.80	106.54	7.74	7.83%
	1,300	106.40	114.78	8.38	7.88%
	1,400	114.00	123.03	9.03	7.92%
	1,500	121.61	131.27	9.66	7.94%
	1,600	129.21	139.52	10.31	7.98%
	1,700	136.81	147.77	10.96	8.01%
	1,800	144.41	156.01	11.60	8.03%
	1,900	152.01	164.26	12.25	8.06%
	2,000	159.61	172.50	12.89	8.08%
	2,200	174.81	188.99	14.18	8.11%
	2,400	190.01	205.48	15.47	8.14%
	2,600	205.22	221.98	16.76	8.17%
	2,800	220.42	238.47	18.05	8.19%
	3,000	235.62	254.96	19.34	8.21%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
E-12 to E-12 with Transition Summer (May - October)

EAA-5

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	774	77.35	83.52	6.17	8.0%
Median	617	60.78	65.37	4.59	7.6%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	200	22.73	23.94	1.21	5.3%
	250	26.52	28.03	1.51	5.7%
	300	30.30	32.12	1.82	6.0%
	350	34.09	36.21	2.12	6.2%
	400	37.87	40.30	2.43	6.4%
	450	43.15	46.07	2.92	6.8%
	500	48.43	51.85	3.42	7.1%
	550	53.70	57.63	3.93	7.3%
	600	58.98	63.41	4.43	7.5%
	650	64.26	69.19	4.93	7.7%
	700	69.54	74.97	5.43	7.8%
	750	74.82	80.75	5.93	7.9%
	800	80.09	86.52	6.43	8.0%
	850	86.25	93.30	7.05	8.2%
	900	92.41	100.08	7.67	8.3%
	950	98.57	106.85	8.28	8.4%
	1,000	104.72	113.63	8.91	8.5%
	1,100	117.04	127.18	10.14	8.7%
	1,200	129.35	140.73	11.38	8.8%
	1,300	141.66	154.28	12.62	8.9%
	1,400	153.98	167.84	13.86	9.0%
	1,500	166.29	181.39	15.10	9.1%
	1,600	178.61	194.94	16.33	9.1%
	1,700	190.92	208.49	17.57	9.2%
	1,800	203.23	222.04	18.81	9.3%
	1,900	215.55	235.60	20.05	9.3%
	2,000	227.86	249.15	21.29	9.3%
	2,200	252.49	276.25	23.76	9.4%
	2,400	277.12	303.35	26.23	9.5%
	2,600	301.75	330.46	28.71	9.5%
	2,800	326.37	357.56	31.19	9.6%
	3,000	351.00	384.67	33.67	9.6%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
E-12 to E-12 with Transition Winter (November-April)

EAA-5

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	582	50.43	54.16	3.73	7.40%
Median	476	42.63	45.67	3.04	7.13%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	200	22.31	23.59	1.28	5.74%
	250	25.99	27.59	1.60	6.16%
	300	29.67	31.59	1.92	6.47%
	350	33.35	35.59	2.24	6.72%
	400	37.03	39.59	2.56	6.91%
	450	40.71	43.59	2.88	7.07%
	500	44.40	47.60	3.20	7.21%
	550	48.08	51.60	3.52	7.32%
	600	51.76	55.60	3.84	7.42%
	650	55.44	59.60	4.16	7.50%
	700	59.12	63.60	4.48	7.58%
	750	62.80	67.60	4.80	7.64%
	800	66.48	71.60	5.12	7.70%
	850	70.16	75.60	5.44	7.75%
	900	73.84	79.60	5.76	7.80%
	950	77.52	83.60	6.08	7.84%
	1,000	81.20	87.60	6.40	7.88%
	1,100	88.56	95.60	7.04	7.95%
	1,200	95.92	103.60	7.68	8.01%
	1,300	103.28	111.60	8.32	8.06%
	1,400	110.64	119.60	8.96	8.10%
	1,500	118.01	127.61	9.60	8.13%
	1,600	125.37	135.61	10.24	8.17%
	1,700	132.73	143.61	10.88	8.20%
	1,800	140.09	151.61	11.52	8.22%
	1,900	147.45	159.61	12.16	8.25%
	2,000	154.81	167.61	12.80	8.27%
	2,200	169.53	183.61	14.08	8.31%
	2,400	184.25	199.61	15.36	8.34%
	2,600	198.98	215.62	16.64	8.36%
	2,800	213.70	231.62	17.92	8.39%
	3,000	228.42	247.62	19.20	8.41%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
EC-1 to EC-1 Interim Based on No Transition Rate Summer (May-October)

EAA-5

Customer Bills at Varying Consumption Levels

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	9	34%	2255	188.78	211.40	22.62	11.98%
Median	8	35%	2030	169.91	190.17	20.26	11.92%

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	3	20%	438	57.14	62.81	5.67	9.92%
	3	30%	657	65.78	72.75	6.97	10.60%
	3	40%	876	74.41	82.69	8.28	11.13%
	3	50%	1,095	83.05	92.62	9.57	11.52%
	3	75%	1,643	104.65	117.49	12.84	12.27%
	5	20%	730	88.65	98.11	9.46	10.67%
	5	30%	1,095	103.05	114.67	11.62	11.28%
	5	40%	1,460	117.44	131.23	13.79	11.74%
	5	50%	1,825	131.83	147.79	15.96	12.11%
	5	75%	2,738	167.83	189.22	21.39	12.75%
	8	20%	1,168	135.92	151.05	15.13	11.13%
	8	30%	1,752	158.95	177.55	18.60	11.70%
	8	40%	2,336	181.98	204.05	22.07	12.13%
	8	50%	2,920	205.01	230.55	25.54	12.46%
	8	75%	4,380	262.57	296.80	34.23	13.04%
	10	20%	1,460	167.44	186.35	18.91	11.29%
	10	30%	2,190	196.22	219.47	23.25	11.85%
	10	40%	2,920	225.01	252.60	27.59	12.26%
	10	50%	3,650	253.79	285.72	31.93	12.58%
	10	75%	5,475	325.75	368.53	42.78	13.13%
	12	20%	1,752	198.95	221.64	22.69	11.40%
	12	30%	2,628	233.49	261.39	27.90	11.95%
	12	40%	3,504	268.03	301.14	33.11	12.35%
	12	50%	4,380	302.57	340.89	38.32	12.66%
	12	75%	6,570	388.93	440.26	51.33	13.20%
	15	20%	2,190	246.22	274.59	28.37	11.52%
	15	30%	3,285	289.40	324.27	34.87	12.05%
	15	40%	4,380	332.57	373.96	41.39	12.45%
	15	50%	5,475	375.75	423.64	47.89	12.75%
	15	75%	8,213	483.71	547.88	64.17	13.27%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
EC-1 to EC-1 Interim Based on No Transition Rate Summer (May-October)

EAA-5

Customer Bills at Varying Consumption Levels

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	9	34%	2255	188.78	211.40	22.62	11.98%
Median	8	35%	2030	169.91	190.17	20.26	11.92%

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	3	20%	438	57.14	62.81	5.67	9.92%
	3	30%	657	65.78	72.75	6.97	10.60%
	3	40%	876	74.41	82.69	8.28	11.13%
	3	50%	1,095	83.05	92.62	9.57	11.52%
	3	75%	1,643	104.65	117.49	12.84	12.27%
	5	20%	730	88.65	98.11	9.46	10.67%
	5	30%	1,095	103.05	114.67	11.62	11.28%
	5	40%	1,460	117.44	131.23	13.79	11.74%
	5	50%	1,825	131.83	147.79	15.96	12.11%
	5	75%	2,738	167.83	189.22	21.39	12.75%
	8	20%	1,168	135.92	151.05	15.13	11.13%
	8	30%	1,752	158.95	177.55	18.60	11.70%
	8	40%	2,336	181.98	204.05	22.07	12.13%
	8	50%	2,920	205.01	230.55	25.54	12.46%
	8	75%	4,380	262.57	296.80	34.23	13.04%
	10	20%	1,460	167.44	186.35	18.91	11.29%
	10	30%	2,190	196.22	219.47	23.25	11.85%
	10	40%	2,920	225.01	252.60	27.59	12.26%
	10	50%	3,650	253.79	285.72	31.93	12.58%
	10	75%	5,475	325.75	368.53	42.78	13.13%
	12	20%	1,752	198.95	221.64	22.69	11.40%
	12	30%	2,628	233.49	261.39	27.90	11.95%
	12	40%	3,504	268.03	301.14	33.11	12.35%
	12	50%	4,380	302.57	340.89	38.32	12.66%
	12	75%	6,570	388.93	440.26	51.33	13.20%
	15	20%	2,190	246.22	274.59	28.37	11.52%
	15	30%	3,285	289.40	324.27	34.87	12.05%
	15	40%	4,380	332.57	373.96	41.39	12.45%
	15	50%	5,475	375.75	423.64	47.89	12.75%
	15	75%	8,213	483.71	547.88	64.17	13.27%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
ET-1 to ET-1 with Transition Summer (May - October)

EAA-5

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	1,801	158.75	176.55	17.80	11.21%
Median	1,634	145.40	161.55	16.15	11.11%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Consumption	200	30.78	32.75	1.97	6.40%
	250	34.77	37.24	2.47	7.10%
	300	38.77	41.74	2.97	7.66%
	350	42.77	46.23	3.46	8.09%
	400	46.76	50.72	3.96	8.47%
	450	50.76	55.21	4.45	8.77%
	500	54.76	59.70	4.94	9.02%
	550	58.75	64.19	5.44	9.26%
	600	62.75	68.68	5.93	9.45%
	650	66.75	73.17	6.42	9.62%
	700	70.74	77.66	6.92	9.78%
	750	74.74	82.15	7.41	9.91%
	800	78.74	86.64	7.90	10.03%
	850	82.73	91.14	8.41	10.17%
	900	86.73	95.63	8.90	10.26%
	950	90.73	100.12	9.39	10.35%
	1,000	94.73	104.61	9.88	10.43%
	1,100	102.72	113.59	10.87	10.58%
	1,200	110.71	122.57	11.86	10.71%
	1,300	118.71	131.55	12.84	10.82%
	1,400	126.70	140.54	13.84	10.92%
	1,500	134.69	149.52	14.83	11.01%
	1,600	142.69	158.50	15.81	11.08%
	1,700	150.68	167.48	16.80	11.15%
	1,800	158.67	176.46	17.79	11.21%
	1,900	166.67	185.45	18.78	11.27%
	2,000	174.66	194.43	19.77	11.32%
	2,200	190.65	212.39	21.74	11.40%
	2,400	206.63	230.35	23.72	11.48%
	2,600	222.62	248.32	25.70	11.54%
	2,800	238.61	266.28	27.67	11.60%
	3,000	254.60	284.25	29.65	11.65%

ET-1 Summer Average Energy On-Peak: 41%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
ET-1 to ET-1 with Transition Winter (November-April)

EAA-5

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	1063	82.77	90.62	7.85	9.48%
Median	929	74.20	81.06	6.86	9.25%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	250	30.78	32.62	1.84	5.98%
	300	33.97	36.19	2.22	6.54%
	350	37.17	39.76	2.59	6.97%
	400	40.37	43.33	2.96	7.33%
	450	43.57	46.89	3.32	7.62%
	500	46.76	50.46	3.70	7.91%
	550	49.96	54.03	4.07	8.15%
	600	53.16	57.59	4.43	8.33%
	650	56.36	61.16	4.80	8.52%
	700	59.55	64.73	5.18	8.70%
	750	62.75	68.29	5.54	8.83%
	800	65.95	71.86	5.91	8.96%
	850	69.15	75.43	6.28	9.08%
	900	72.34	78.99	6.65	9.19%
	950	75.54	82.56	7.02	9.29%
	1,000	78.74	86.13	7.39	9.39%
	1,100	85.13	93.26	8.13	9.55%
	1,200	91.53	100.40	8.87	9.69%
	1,300	97.92	107.53	9.61	9.81%
	1,400	104.32	114.66	10.34	9.91%
	1,500	110.71	121.80	11.09	10.02%
	1,600	117.11	128.93	11.82	10.09%
	1,700	123.50	136.06	12.56	10.17%
	1,800	129.90	143.20	13.30	10.24%
	1,900	136.29	150.33	14.04	10.30%
	2,000	142.69	157.47	14.78	10.36%
	2,200	155.48	171.73	16.25	10.45%
	2,400	168.27	186.00	17.73	10.54%
	2,600	181.06	200.27	19.21	10.61%
	2,800	193.85	214.54	20.69	10.67%
	3,000	206.63	228.80	22.17	10.73%

ET-1 Winter Average Energy On-Peak: 33%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
ECT-1R to ECT-1R with Transition Summer (May-October)

EAA-5

Customer Bills at Varying Consumption Levels

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	10	41%	2959	236.73	262.56	25.83	10.91%
Median	8.9	41%	2662	213.31	236.52	23.21	10.88%

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	3	20%	438	65.59	69.91	4.32	6.59%
	3	30%	657	73.28	79.27	5.99	8.17%
	3	40%	876	80.96	88.62	7.66	9.46%
	3	50%	1,095	88.65	97.97	9.32	10.51%
	3	75%	1,643	107.88	121.37	13.49	12.50%
	5	20%	730	99.46	106.66	7.20	7.24%
	5	30%	1,095	112.27	122.25	9.98	8.89%
	5	40%	1,460	125.07	137.84	12.77	10.21%
	5	50%	1,825	137.88	153.43	15.55	11.28%
	5	75%	2,738	169.92	192.42	22.50	13.24%
	8	20%	1,168	150.26	161.79	11.53	7.67%
	8	30%	1,752	170.75	186.73	15.98	9.36%
	8	40%	2,336	191.24	211.67	20.43	10.68%
	8	50%	2,920	211.74	236.61	24.87	11.75%
	8	75%	4,380	262.97	298.96	35.99	13.69%
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	10	20%	1,460	184.12	198.54	14.42	7.83%
	10	30%	2,190	209.74	229.71	19.97	9.52%
	10	40%	2,920	235.36	260.89	25.53	10.85%
	10	50%	3,650	260.98	292.06	31.08	11.91%
	10	75%	5,475	325.02	370.00	44.98	13.84%
	12	20%	1,752	217.99	235.29	17.30	7.94%
	12	30%	2,628	248.73	272.70	23.97	9.64%
	12	40%	3,504	279.47	310.11	30.64	10.96%
	12	50%	4,380	310.21	347.52	37.31	12.03%
	12	75%	6,570	387.06	441.04	53.98	13.95%
	15	20%	2,190	268.79	290.41	21.62	8.04%
	15	30%	3,285	307.22	337.18	29.96	9.75%
	15	40%	4,380	345.64	383.94	38.30	11.08%
	15	50%	5,475	384.07	430.70	46.63	12.14%
	15	75%	8,213	480.15	547.63	67.48	14.05%

ECT-1R Summer Average Energy On-Peak: 40%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
ECT-1R to ECT-1R with Transition Winter (November-April)

EAA-5

Customer Bills at Varying Consumption Levels

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	7	36%	1833	124.95	137.71	12.76	10.21%
Median	6.4	34%	1603	113.38	124.60	11.22	9.90%

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	3	20%	438	51.88	55.19	3.31	6.38%
	3	30%	657	58.26	62.93	4.67	8.02%
	3	40%	876	64.64	70.66	6.02	9.31%
	3	50%	1,095	71.01	78.40	7.39	10.41%
	3	75%	1,643	86.98	97.76	10.78	12.39%
	5	20%	730	76.60	82.13	5.53	7.22%
	5	30%	1,095	87.23	95.02	7.79	8.93%
	5	40%	1,460	97.87	107.91	10.04	10.26%
	5	50%	1,825	108.50	120.81	12.31	11.35%
	5	75%	2,738	135.09	153.06	17.97	13.30%
	8	20%	1,168	113.69	122.53	8.84	7.78%
	8	30%	1,752	130.70	143.16	12.46	9.53%
	8	40%	2,336	147.71	163.79	16.08	10.89%
	8	50%	2,920	164.72	184.42	19.70	11.96%
	8	75%	4,380	207.25	235.99	28.74	13.87%
	10	20%	1,460	138.42	149.46	11.04	7.98%
	10	30%	2,190	159.68	175.25	15.57	9.75%
	10	40%	2,920	180.94	201.04	20.10	11.11%
	10	50%	3,650	202.20	226.82	24.62	12.18%
	10	75%	5,475	255.36	291.29	35.93	14.07%
	12	20%	1,752	163.14	176.40	13.26	8.13%
	12	30%	2,628	188.66	207.34	18.68	9.90%
	12	40%	3,504	214.17	238.29	24.12	11.26%
	12	50%	4,380	239.69	269.23	29.54	12.32%
	12	75%	6,570	303.48	346.59	43.11	14.21%
	15	20%	2,190	200.23	216.80	16.57	8.28%
	15	30%	3,285	232.12	255.48	23.36	10.06%
	15	40%	4,380	264.02	294.16	30.14	11.42%
	15	50%	5,475	295.91	332.84	36.93	12.48%
	15	75%	8,213	375.66	429.56	53.90	14.35%

ECT-1R Winter Average Energy On-Peak: 32%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

EAA-6

Typical Bill Analysis Informational Scenario #2
No Customer Transition

Arizona Public Service Company

Typical Residential Bill Analysis
E-10 to E-10 No Transition Summer (May - October)

EAA-6

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	942	87.13	98.38	11.25	12.91%
Median	727	66.34	74.46	8.12	12.24%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	200	21.45	23.57	2.12	9.88%
	250	24.91	27.56	2.65	10.64%
	300	28.38	31.55	3.17	11.17%
	350	31.84	35.55	3.71	11.65%
	400	35.31	39.54	4.23	11.98%
	450	40.05	44.88	4.83	12.06%
	500	44.80	50.22	5.42	12.10%
	550	49.54	55.56	6.02	12.15%
	600	54.29	60.90	6.61	12.18%
	650	59.03	66.24	7.21	12.21%
	700	63.78	71.58	7.80	12.23%
	750	68.52	76.92	8.40	12.26%
	800	73.27	82.26	8.99	12.27%
	850	78.15	87.93	9.78	12.51%
	900	83.03	93.61	10.58	12.74%
	950	87.91	99.29	11.38	12.95%
	1,000	92.79	104.96	12.17	13.12%
	1,100	102.55	116.32	13.77	13.43%
	1,200	112.31	127.67	15.36	13.68%
	1,300	122.07	139.03	16.96	13.89%
	1,400	131.83	150.38	18.55	14.07%
	1,500	141.59	161.73	20.14	14.22%
	1,600	151.35	173.09	21.74	14.36%
	1,700	161.11	184.44	23.33	14.48%
	1,800	170.87	195.80	24.93	14.59%
	1,900	180.63	207.15	26.52	14.68%
	2,000	190.39	218.50	28.11	14.76%
	2,200	209.91	241.21	31.30	14.91%
	2,400	229.43	263.92	34.49	15.03%
	2,600	248.95	286.63	37.68	15.14%
	2,800	268.47	309.34	40.87	15.22%
	3,000	287.99	332.04	44.05	15.30%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
E-10 to E-10 No Transition Winter (November-April)

EAA-6

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	705	61.18	65.72	4.54	7.42%
Median	574	51.22	54.92	3.70	7.22%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	200	22.79	24.08	1.29	5.66%
	250	26.59	28.20	1.61	6.05%
	300	30.39	32.33	1.94	6.38%
	350	34.19	36.45	2.26	6.61%
	400	37.99	40.57	2.58	6.79%
	450	41.79	44.70	2.91	6.96%
	500	45.60	48.82	3.22	7.06%
	550	49.40	52.94	3.54	7.17%
	600	53.20	57.06	3.86	7.26%
	650	57.00	61.19	4.19	7.35%
	700	60.80	65.31	4.51	7.42%
	750	64.60	69.43	4.83	7.48%
	800	68.40	73.55	5.15	7.53%
	850	72.20	77.68	5.48	7.59%
	900	76.00	81.80	5.80	7.63%
	950	79.80	85.92	6.12	7.67%
	1,000	83.60	90.05	6.45	7.72%
	1,100	91.20	98.29	7.09	7.77%
	1,200	98.80	106.54	7.74	7.83%
	1,300	106.40	114.78	8.38	7.88%
	1,400	114.00	123.03	9.03	7.92%
	1,500	121.61	131.27	9.66	7.94%
	1,600	129.21	139.52	10.31	7.98%
	1,700	136.81	147.77	10.96	8.01%
	1,800	144.41	156.01	11.60	8.03%
	1,900	152.01	164.26	12.25	8.06%
	2,000	159.61	172.50	12.89	8.08%
	2,200	174.81	188.99	14.18	8.11%
	2,400	190.01	205.48	15.47	8.14%
	2,600	205.22	221.98	16.76	8.17%
	2,800	220.42	238.47	18.05	8.19%
	3,000	235.62	254.96	19.34	8.21%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
E-12 to E-12 No Transition Summer (May - October)

EAA-6

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	774	77.35	85.01	7.66	9.9%
Median	617	60.78	66.49	5.71	9.4%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	200	22.73	24.24	1.51	6.6%
	250	26.52	28.41	1.89	7.1%
	300	30.30	32.57	2.27	7.5%
	350	34.09	36.73	2.64	7.7%
	400	37.87	40.89	3.02	8.0%
	450	43.15	46.79	3.64	8.4%
	500	48.43	52.69	4.26	8.8%
	550	53.70	58.59	4.89	9.1%
	600	58.98	64.48	5.50	9.3%
	650	64.26	70.38	6.12	9.5%
	700	69.54	76.28	6.74	9.7%
	750	74.82	82.18	7.36	9.8%
	800	80.09	88.07	7.98	10.0%
	850	86.25	95.04	8.79	10.2%
	900	92.41	102.01	9.60	10.4%
	950	98.57	108.97	10.40	10.6%
	1,000	104.72	115.94	11.22	10.7%
	1,100	117.04	129.87	12.83	11.0%
	1,200	129.35	143.80	14.45	11.2%
	1,300	141.66	157.73	16.07	11.3%
	1,400	153.98	171.67	17.69	11.5%
	1,500	166.29	185.60	19.31	11.6%
	1,600	178.61	199.53	20.92	11.7%
	1,700	190.92	213.46	22.54	11.8%
	1,800	203.23	227.39	24.16	11.9%
	1,900	215.55	241.33	25.78	12.0%
	2,000	227.86	255.26	27.40	12.0%
	2,200	252.49	283.12	30.63	12.1%
	2,400	277.12	310.99	33.87	12.2%
	2,600	301.75	338.85	37.10	12.3%
	2,800	326.37	366.71	40.34	12.4%
	3,000	351.00	394.58	43.58	12.4%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
E-12 to E-12 No Transition Winter (November-April)

EAA-6

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	582	50.43	54.52	4.09	8.11%
Median	476	42.63	45.97	3.34	7.83%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	200	22.31	23.72	1.41	6.32%
	250	25.99	27.75	1.76	6.77%
	300	29.67	31.78	2.11	7.11%
	350	33.35	35.81	2.46	7.38%
	400	37.03	39.84	2.81	7.59%
	450	40.71	43.88	3.17	7.79%
	500	44.40	47.91	3.51	7.91%
	550	48.08	51.94	3.86	8.03%
	600	51.76	55.97	4.21	8.13%
	650	55.44	60.00	4.56	8.23%
	700	59.12	64.03	4.91	8.31%
	750	62.80	68.07	5.27	8.39%
	800	66.48	72.10	5.62	8.45%
	850	70.16	76.13	5.97	8.51%
	900	73.84	80.16	6.32	8.56%
	950	77.52	84.19	6.67	8.60%
	1,000	81.20	88.22	7.02	8.65%
	1,100	88.56	96.29	7.73	8.73%
	1,200	95.92	104.35	8.43	8.79%
	1,300	103.28	112.41	9.13	8.84%
	1,400	110.64	120.48	9.84	8.89%
	1,500	118.01	128.54	10.53	8.92%
	1,600	125.37	136.61	11.24	8.97%
	1,700	132.73	144.67	11.94	9.00%
	1,800	140.09	152.73	12.64	9.02%
	1,900	147.45	160.80	13.35	9.05%
	2,000	154.81	168.86	14.05	9.08%
	2,200	169.53	184.99	15.46	9.12%
	2,400	184.25	201.11	16.86	9.15%
	2,600	198.98	217.24	18.26	9.18%
	2,800	213.70	233.37	19.67	9.20%
	3,000	228.42	249.49	21.07	9.22%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
EC-1 to EC-1 No Transition Summer (May-October)

EAA-6

Customer Bills at Varying Consumption Levels

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	9	34%	2255	188.78	211.40	22.62	11.98%
Median	8	35%	2030	169.91	190.17	20.26	11.92%

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	3	20%	438	57.14	62.81	5.67	9.92%
	3	30%	657	65.78	72.75	6.97	10.60%
	3	40%	876	74.41	82.69	8.28	11.13%
	3	50%	1,095	83.05	92.62	9.57	11.52%
	3	75%	1,643	104.65	117.49	12.84	12.27%
	5	20%	730	88.65	98.11	9.46	10.67%
	5	30%	1,095	103.05	114.67	11.62	11.28%
	5	40%	1,460	117.44	131.23	13.79	11.74%
	5	50%	1,825	131.83	147.79	15.96	12.11%
	5	75%	2,738	167.83	189.22	21.39	12.75%
	8	20%	1,168	135.92	151.05	15.13	11.13%
	8	30%	1,752	158.95	177.55	18.60	11.70%
	8	40%	2,336	181.98	204.05	22.07	12.13%
	8	50%	2,920	205.01	230.55	25.54	12.46%
	8	75%	4,380	262.57	296.80	34.23	13.04%
	10	20%	1,460	167.44	186.35	18.91	11.29%
	10	30%	2,190	196.22	219.47	23.25	11.85%
	10	40%	2,920	225.01	252.60	27.59	12.26%
	10	50%	3,650	253.79	285.72	31.93	12.58%
	10	75%	5,475	325.75	368.53	42.78	13.13%
	12	20%	1,752	198.95	221.64	22.69	11.40%
	12	30%	2,628	233.49	261.39	27.90	11.95%
	12	40%	3,504	268.03	301.14	33.11	12.35%
	12	50%	4,380	302.57	340.89	38.32	12.66%
	12	75%	6,570	388.93	440.26	51.33	13.20%
	15	20%	2,190	246.22	274.59	28.37	11.52%
	15	30%	3,285	289.40	324.27	34.87	12.05%
	15	40%	4,380	332.57	373.96	41.39	12.45%
	15	50%	5,475	375.75	423.64	47.89	12.75%
	15	75%	8,213	483.71	547.88	64.17	13.27%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
EC-1 to EC-1 No Transition Winter (November-April)

EAA-6

Customer Bills at Varying Consumption Levels

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	7	29%	1489	103.91	113.31	9.40	9.05%
Median	7	26%	1319	98.85	108.00	9.15	9.26%

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	3	20%	438	44.21	47.95	3.74	8.46%
	3	30%	657	50.74	54.79	4.05	7.98%
	3	40%	876	57.26	61.63	4.37	7.63%
	3	50%	1,095	63.78	68.47	4.69	7.35%
	3	75%	1,643	80.10	85.59	5.49	6.85%
	5	20%	730	67.11	73.34	6.23	9.28%
	5	30%	1,095	77.98	84.74	6.76	8.67%
	5	40%	1,460	88.85	96.14	7.29	8.20%
	5	50%	1,825	99.72	107.54	7.82	7.84%
	5	75%	2,738	126.91	136.07	9.16	7.22%
	8	20%	1,168	101.45	111.41	9.96	9.82%
	8	30%	1,752	118.84	129.66	10.82	9.10%
	8	40%	2,336	136.24	147.90	11.66	8.56%
	8	50%	2,920	153.63	166.15	12.52	8.15%
	8	75%	4,380	197.11	211.76	14.65	7.43%
	10	20%	1,460	124.35	136.80	12.45	10.01%
	10	30%	2,190	146.09	159.61	13.52	9.25%
	10	40%	2,920	167.83	182.41	14.58	8.69%
	10	50%	3,650	189.57	205.22	15.65	8.26%
	10	75%	5,475	243.92	262.23	18.31	7.51%
	12	20%	1,752	147.24	162.19	14.95	10.15%
	12	30%	2,628	173.33	189.55	16.22	9.36%
	12	40%	3,504	199.42	216.92	17.50	8.78%
	12	50%	4,380	225.51	244.29	18.78	8.33%
	12	75%	6,570	290.72	312.70	21.98	7.56%
	15	20%	2,190	181.59	200.27	18.68	10.29%
	15	30%	3,285	214.20	234.47	20.27	9.46%
	15	40%	4,380	246.81	268.68	21.87	8.86%
	15	50%	5,475	279.42	302.89	23.47	8.40%
	15	75%	8,213	360.95	388.42	27.47	7.61%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
ET-1 to ET-1 No Transition Summer (May - October)

EAA-6

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	1,801	158.75	176.53	17.78	11.20%
Median	1,634	145.40	161.54	16.14	11.10%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Consumption	200	30.78	32.75	1.97	6.40%
	250	34.77	37.24	2.47	7.10%
	300	38.77	41.73	2.96	7.63%
	350	42.77	46.22	3.45	8.07%
	400	46.76	50.71	3.95	8.45%
	450	50.76	55.20	4.44	8.75%
	500	54.76	59.69	4.93	9.00%
	550	58.75	64.18	5.43	9.24%
	600	62.75	68.67	5.92	9.43%
	650	66.75	73.16	6.41	9.60%
	700	70.74	77.66	6.92	9.78%
	750	74.74	82.15	7.41	9.91%
	800	78.74	86.64	7.90	10.03%
	850	82.73	91.13	8.40	10.15%
	900	86.73	95.62	8.89	10.25%
	950	90.73	100.11	9.38	10.34%
	1,000	94.73	104.60	9.87	10.42%
	1,100	102.72	113.58	10.86	10.57%
	1,200	110.71	122.56	11.85	10.70%
	1,300	118.71	131.54	12.83	10.81%
	1,400	126.70	140.52	13.82	10.91%
	1,500	134.69	149.50	14.81	11.00%
	1,600	142.69	158.48	15.79	11.07%
	1,700	150.68	167.46	16.78	11.14%
	1,800	158.67	176.44	17.77	11.20%
	1,900	166.67	185.42	18.75	11.25%
	2,000	174.66	194.40	19.74	11.30%
	2,200	190.65	212.37	21.72	11.39%
	2,400	206.63	230.33	23.70	11.47%
	2,600	222.62	248.29	25.67	11.53%
	2,800	238.61	266.25	27.64	11.58%
	3,000	254.60	284.21	29.61	11.63%

ET-1 Summer Average Energy On-Peak: 41%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
ET-1 to ET-1 No Transition Winter (November-April)

EAA-6

Customer Bills at Varying Consumption Levels

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	1063	82.77	90.61	7.84	9.47%
Median	929	74.20	81.05	6.85	9.23%

Consumption	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	250	30.78	32.62	1.84	5.98%
	300	33.97	36.19	2.22	6.54%
	350	37.17	39.75	2.58	6.94%
	400	40.37	43.32	2.95	7.31%
	450	43.57	46.89	3.32	7.62%
	500	46.76	50.45	3.69	7.89%
	550	49.96	54.02	4.06	8.13%
	600	53.16	57.59	4.43	8.33%
	650	56.36	61.15	4.79	8.50%
	700	59.55	64.72	5.17	8.68%
	750	62.75	68.29	5.54	8.83%
	800	65.95	71.85	5.90	8.95%
	850	69.15	75.42	6.27	9.07%
	900	72.34	78.99	6.65	9.19%
	950	75.54	82.55	7.01	9.28%
	1,000	78.74	86.12	7.38	9.37%
	1,100	85.13	93.25	8.12	9.54%
	1,200	91.53	100.38	8.85	9.67%
	1,300	97.92	107.52	9.60	9.80%
	1,400	104.32	114.65	10.33	9.90%
	1,500	110.71	121.78	11.07	10.00%
	1,600	117.11	128.91	11.80	10.08%
	1,700	123.50	136.05	12.55	10.16%
	1,800	129.90	143.18	13.28	10.22%
	1,900	136.29	150.31	14.02	10.29%
	2,000	142.69	157.45	14.76	10.34%
	2,200	155.48	171.71	16.23	10.44%
	2,400	168.27	185.98	17.71	10.52%
	2,600	181.06	200.24	19.18	10.59%
	2,800	193.85	214.51	20.66	10.66%
	3,000	206.63	228.77	22.14	10.71%

ET-1 Winter Average Energy On-Peak: 33%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
ECT-1R to ECT-1R No Transition Summer (May-October)

EAA-6

Customer Bills at Varying Consumption Levels

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	10	41%	2959	236.73	263.04	26.31	11.11%
Median	8.9	41%	2662	213.31	236.96	23.65	11.09%

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	3	20%	438	65.59	70.00	4.41	6.72%
	3	30%	657	73.28	79.38	6.10	8.32%
	3	40%	876	80.96	88.76	7.80	9.63%
	3	50%	1,095	88.65	98.15	9.50	10.72%
	3	75%	1,643	107.88	121.63	13.75	12.75%
	5	20%	730	99.46	106.81	7.35	7.39%
	5	30%	1,095	112.27	122.44	10.17	9.06%
	5	40%	1,460	125.07	138.08	13.01	10.40%
	5	50%	1,825	137.88	153.72	15.84	11.49%
	5	75%	2,738	169.92	192.84	22.92	13.49%
	8	20%	1,168	150.26	162.01	11.75	7.82%
	8	30%	1,752	170.75	187.04	16.29	9.54%
	8	40%	2,336	191.24	212.06	20.82	10.89%
	8	50%	2,920	211.74	237.08	25.34	11.97%
	8	75%	4,380	262.97	299.63	36.66	13.94%
	10	20%	1,460	184.12	198.82	14.70	7.98%
	10	30%	2,190	209.74	230.10	20.36	9.71%
	10	40%	2,920	235.36	261.37	26.01	11.05%
	10	50%	3,650	260.98	292.65	31.67	12.14%
	10	75%	5,475	325.02	370.84	45.82	14.10%
	12	20%	1,752	217.99	235.63	17.64	8.09%
	12	30%	2,628	248.73	273.16	24.43	9.82%
	12	40%	3,504	279.47	310.69	31.22	11.17%
	12	50%	4,380	310.21	348.22	38.01	12.25%
	12	75%	6,570	387.06	442.05	54.99	14.21%
	15	20%	2,190	268.79	290.84	22.05	8.20%
	15	30%	3,285	307.22	337.75	30.53	9.94%
	15	40%	4,380	345.64	384.66	39.02	11.29%
	15	50%	5,475	384.07	431.58	47.51	12.37%
	15	75%	8,213	480.15	548.89	68.74	14.32%

ECT-1R Summer Average Energy On-Peak: 40%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Arizona Public Service Company

Typical Residential Bill Analysis
ECT-1R to ECT-1R No Transition Winter (November-April)

EAA-6

Customer Bills at Varying Consumption Levels

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
Average	7	36%	1833	124.95	138.33	13.38	10.71%
Median	6.4	34%	1603	113.38	125.14	11.76	10.37%

Consumption	Monthly kW	Load Factor	Monthly kWh	Present Rates Base Rate	Proposed Rates Base Rate	Dollar Increase	Percent Increase
	3	20%	438	51.88	55.35	3.47	6.69%
	3	30%	657	58.26	63.15	4.89	8.39%
	3	40%	876	64.64	70.96	6.32	9.78%
	3	50%	1,095	71.01	78.76	7.75	10.91%
	3	75%	1,643	86.98	98.28	11.30	12.99%
	5	20%	730	76.60	82.39	5.79	7.56%
	5	30%	1,095	87.23	95.40	8.17	9.37%
	5	40%	1,460	97.87	108.40	10.53	10.76%
	5	50%	1,825	108.50	121.40	12.90	11.89%
	5	75%	2,738	135.09	153.93	18.84	13.95%
	8	20%	1,168	113.69	122.96	9.27	8.15%
	8	30%	1,752	130.70	143.76	13.06	9.99%
	8	40%	2,336	147.71	164.57	16.86	11.41%
	8	50%	2,920	164.72	185.37	20.65	12.54%
	8	75%	4,380	207.25	237.38	30.13	14.54%
	10	20%	1,460	138.42	150.00	11.58	8.37%
	10	30%	2,190	159.68	176.00	16.32	10.22%
	10	40%	2,920	180.94	202.01	21.07	11.64%
	10	50%	3,650	202.20	228.02	25.82	12.77%
	10	75%	5,475	255.36	293.03	37.67	14.75%
	12	20%	1,752	163.14	177.04	13.90	8.52%
	12	30%	2,628	188.66	208.25	19.59	10.38%
	12	40%	3,504	214.17	239.45	25.28	11.80%
	12	50%	4,380	239.69	270.66	30.97	12.92%
	12	75%	6,570	303.48	348.68	45.20	14.89%
	15	20%	2,190	200.23	217.60	17.37	8.68%
	15	30%	3,285	232.12	256.61	24.49	10.55%
	15	40%	4,380	264.02	295.62	31.60	11.97%
	15	50%	5,475	295.91	334.63	38.72	13.09%
	15	75%	8,213	375.66	432.17	56.51	15.04%

ECT-1R Winter Average Energy On-Peak: 32%

NOTES TO SCHEDULE:

1) Bills do not include PSA, EPS, CRCC, Surcharges, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 4/1/2005.
3) Average and median consumption is based on the seasonal average.

Exhibit A

APS Customer Transition Plan

ARIZONA CORPORATION COMMISSION
STAFF'S FIFTEENTH SET OF DATA REQUESTS
REGARDING ARIZONA PUBLIC SERVICE COMPANY RATE CASE
DOCKET NO. E-01345A-05-0816
JULY 28, 2006

Customer Transition Plan

EAA 15-1 Please provide APS' customer transition plan that explains how all customers on EC-1, E-10, E-21, E-22, E-23, E-24, and E-38 will be educated about appropriate alternative rate schedules. At a minimum, please provide the following information in the customer transition plan:

a) Please identify the default rates and explain why they are an appropriate rate substitute.

b) Please identify all customer notification and education strategies and associated timeframes.

c) Please identify the timeframe in which customers will be placed on the default rate if the customer takes no action.

d) Please explain in detail the type of rate analysis will be made available to each customer in an effort to choose an appropriate alternative rate. What tools will be utilized by the customer and or the customer service representative.

e) Please provide a copy of proposed bill messages and written communications that will be provided to customers.

f) Please provide a copy of proposed script(s) used for outbound recorded messages or customer service personnel who are responding to customer inquiries.

g) Please provide a description of the training efforts that will occur to ensure that all customer service personnel will be prepared to provide accurate information about the customer transition process and rate analysis.

Response:

a) Commercial customers on the general service time-of-use rates E-21, E-22, E-23 or E-24 will be initially placed on general service time-of-use rate E-32 TOU because it is the alternate general service time-of-use rate for this customer group and would not require a meter change. The Company will perform a rate comparison for each customer to determine the customer's projected energy bill on E-32 and E-32 TOU. The results of the rate comparison will be communicated to each customer who will

be able to choose their best rate option. If the customer chooses E-32, a meter change will be required. The time required for a meter change will vary based on meter equipment availability and scheduling.

Commercial customers on the agricultural irrigation service rates E-38 or E-38-8T will be transferred to rate schedule E-221, which is the alternate option for water pumping service.

Residential customers, on the E-10 and EC-1 rates, will be placed on an interim rate E-10 and EC-1 respectively that will bring their energy costs in line with their cost-of-service. This will allow a transition period for customers to choose a new rate schedule. The interim rate E-10 will have the same structure as the current rate E-10. The interim rate EC-1 will have the same structure as the current rate EC-1. Customers on these interim rates will be provided six months to review the remaining five rate schedules and make their selection. At the end of the six month period, customers who have not made a selection will be transferred to a default rate. Based on an analysis of the most appropriate rate replacement for our customers on the E-10 and EC-1 frozen rates, APS proposes the following default rates:

- For E-10 customers consuming more than 1,000 kWh/month (annual average), the default rate will be ET-1 rate plan (the Time Advantage 9 p.m. - 9 a.m. Plan).
- For EC-1 customers consuming more than 1,000 kWh/month (annual average), the default rate will be ECT-1R rate plan.
- For EC-1 and E-10 customers consuming less than 1,000 kWh/month (annual average), the default rate will be E-12 rate plan.

The Company believes that these residential default rates are the best options for the majority of customers in each rate and usage category, based on comparisons of expected monthly bills for various rate options.

b) Below are the proposed customer notification and education strategies with the associated timeframes.

Strategy	Tactics
Residential Customers 1) Utilize aps.com as a communication and	a) Provide customers an overview and description of each of the available rate plans on aps.com (*within 2 days following the approval of the rate case*).

education channel for frozen rate customers.	b) Provide customers on-line rate analysis tools to assist customers in selecting the most appropriate rate (*within 2 days following the approval of the rate case*). c) Add a "promo button" to the homepage of aps.com to provide quick navigation to the on-line rate comparison (*within 2 days following the approval of the rate case).*
2) Communicate directly with residential customers multiple times to encourage them to select a new rate plan.	a) Run monthly bill messages to encourage residential frozen rate customers to complete a rate comparison on aps.com and select a new rate (*begin with the first bill cycle that runs following the approval of the rate case*).
	b) Provide a shortcut to the on-line rate comparison tool for customers that receive an e-bill (*begin with the first bill cycle that runs following the approval of the rate case).* c) Send an email to registered aps.com customers informing customers of the elimination of the rate. In the email, provide a link to the on-line rate comparison (*within 1 week following the approval of the rate case*). d) Mail residential customers a direct mail letter that educates customers on the elimination of their rate and the available rate options. In the letter, encourage customers to complete a rate comparison either on aps.com or by calling to speak with an APS associate who can educate customers on the default rates. The mailing will include a postage-paid business reply card (BRC) to encourage customers to select their new rate (*within 1 month following the approval of the rate case*). e) Contact residential customers with a frozen rate, utilizing the predictive dialer to remind customers to select a new rate plan. The message will mention they have until (insert date) to do so or they will automatically be transferred to the appropriate default rate (*1st message will run within 6 weeks following the approval of the rate case; 2nd message will run 1 month before the transfer to the appropriate default rate occurs).*

3) Educate customers on how to use their new plan successfully.	a) Provide ways to maximize savings for the current rate plans on aps.com *(within 2 days following the approval of the rate case)*. b) Provide ways to maximize savings for the current rate plans in the direct mail letter (*within 1 month following the approval of the rate case*). c) If a meter exchange is required, place a door hanger on the customer's door to notify the customers that their new rate is active and reiterate how to maximizing savings on the selected new rate plan (*at time of meter exchange, if meter exchange is required*).
Non-Residential Customers 4) Communicate directly with non-residential customers that their rate has been discontinued and they have been transferred to a new rate.	a) Run a bill message for non-residential customers to notify them that their rate has been eliminated and they are being transferred to a new rate (*begin with the first bill cycle that runs following the approval of the rate case*). b) Mail customers on E-21, E-22, E-23 and E-24 a direct mail letter that communicates the results of the rate comparison comparing E-32 and E-32 TOU (*within 1 month following the approval of the rate case*). c) Conduct a staffed outbound call campaign to inform non-residential TOU rate customers they have been defaulted to the E-32 TOU plan. Convey the results of the rate comparison and discuss the features of each rate (*during a 6 month period following the approval of the rate case; 3 attempts to reach the customer will be made*).
In House Training 5) Educate customer service representatives and field service personnel on the frozen rate elimination.	a) Conduct in-house training sessions with customer service representatives and office personnel to bring them up to speed on the frozen rate transfer plans and inform them of how requests to switch to the new rates should be handled (*training will be completed prior to*

	the approval of the rate case). b) Send out a HotNews email to call center and office customer service representatives on the elimination of the frozen rates. HotNews emails are sent out to inform critical 'need to know' information to customer service representatives. Representatives are advised to immediately read a HotNews email once it is received (*day rate case is approved*). c) Update RepDirect customer service information database to include information on the frozen rate transition plan. The database provides the customer service personnel with the ability to search by a keyword. The database will provide the customer service representative information related to the keyword (*within 1 day following the approval of the rate case*). d) Distribute a handout to call center and office customer service representatives that provides the details of the direct mail letter. The handout will include an overview of the direct mail, key messages communicated in the letter, when the direct mail will begin and other pertinent details the customer service representatives need to know (*3 weeks following the approval of the rate case; 1 week prior to direct mail letter drop*). e) Provide talking points for Call Center Associates (*day the rate case is approved*). f) Provide a pocket card that contains the call center phone number to field service and field collections personnel. The card will be given to customers that request information pertaining to frozen rates in the field *(day the rate case is approved)*. g) Distribute a handout to call center and office customer service representatives on the bill messages. The handout will include the key messages of the bill message and when the bill message will run (*within 3 days following the approval of the rate case*).

	h) Continue to provide updates as the program evolves utilizing the on-line customer service manual, aps.com, handouts, Hot News emails and talking points (*ongoing following the approval of the rate case).*
6) Educate APS employees on the frozen rate elimination.	a) Announce rate plan elimination on APS Newsline. Newsline is an internal electronic news bulletin that is sent to APS employees (*within 1 week following approval of the rate case*).

c) Residential customers placed on the E-10 and EC-1 interim rates will be provided six months to review the five rate schedules and make their new rate selection. At the end of the six month period, residential customers who have not made a selection will be transferred to the appropriate default rate.

Commercial customers on E-21, E-22, E-23 and E-24 will initially be placed on E-32 TOU. The Company will perform a rate comparison for each customer to determine the customer's projected energy bill on E-32 and E-32 TOU. The results of the rate comparison will be communicated to each customer who will be able to choose their best rate option at that time. If the customer chooses E-32, a meter change will be required. The time required for a meter change will vary based on meter equipment availability and scheduling.

At the time the frozen rates are eliminated, commercial customers on the agricultural irrigation service rates E-38 or E-38-8T will be transferred to rate schedule E-221, which is the alternate option for water pumping service.

d) The type of rate analysis available to both the customer and customer service representative will vary depending on whether the customer is a residential or non-residential customer.

Residential Customers

In order to assist residential customers in selecting the most appropriate alternative rate, rate analysis tools will be available to both the customers and the customer service representatives. Residential customers will be

provided rate analysis tools on-line at aps.com. The first tool that will be available to residential customers on aps.com is a quick comparison. The quick comparison will suggest the most appropriate rate plan(s) based on what part of the state the customer lives in, the size of the customer's home in square footage, the customer's monthly kWh usage and the type of energy utilized in the customer's home. The customer will be able to click on each of the suggested rate plans and view a detailed description of the selected plan as well a description of who may benefit on the selected rate. The quick comparison will not take into consideration the customer's actual usage history. The quick comparison will be available to all residential customers.

In addition to the quick comparison, residential customers will also be able to view a side-by- side comparison of the service plan attributes. The comparison of service plan attributes will be provided in a table format. The table will show the customer the service charge per day for each of the available residential rates as well as the square footage parameters for each of the rates. The table will illustrate whether or not the rate is demand based and/or time based. For those rates that are time based, the detailed comparison will provide the off-peak hours, the cost per kWh on-peak and cost per kWh off-peak. For the rates that have a demand component, the cost per kW will be provided. The comparison of service plan attributes will be available to all residential customers.

Also, an on-line rate comparison tool will be available to registered aps.com residential customers. Registered aps.com users have the ability to view their bill and account history on-line. The rate comparison tool will utilize the customer's previous 12 months actual usage history. A bar chart will be utilized to show a visual comparison of what the customer would have paid on each of the available residential rate plans. Each of the bar charts will be labeled to show which plan the bar chart is representing. A "promo button" will be added to the homepage of aps.com to provide quick navigation to the on-line rate comparison.

Residential customers that do not have Internet access or prefer to speak with a customer service representative will have the option to call the APS Customer Care in order to receive assistance in selecting the most appropriate rate. Customer service representatives will utilize a service plan comparison tool in order to aid customers in selecting the most appropriate service plan. The Service Plan Comparison will be available via APS' Customer Information System (CIS). The Service Plan Comparison will allow the customer service representative the ability to explain to the customer what the customer would have paid on each of the

alternative rate options based on the customer's previous 12 months usage history. When comparing a non-TOU rate to a TOU rate, the % On Peak will default to 40% for the 9 p.m. – 9 a.m. plans and 25% for the 7 p.m. – Noon plans. The customer service representative will have the ability to adjust the % On Peak based on information provided by the customer.

Non-Residential Customers

Commercial customers on E-21, E-22, E-23 and E-24 will initially be placed on E-32 TOU. The Company will perform a rate comparison for each customer to determine the customer's projected energy bill on E-32 and E-32 TOU. The results of the rate comparison will be communicated to each customer who will be able to choose their best rate option at that time. If the customer chooses E-32, a meter change will be required. The time required for a meter change will vary based on meter equipment availability and scheduling.

Customer service representatives will conduct an outbound call to each customer on E-21, E-22, E-23 and E-24. The customer service representative will convey the results of the rate comparison and discuss the features of E-32 and E-32 TOU.

There is only one default rate option for E-38 and E-38-8T customers. E-38 and E-38-8T will automatically be transferred to E-221 upon the elimination of E-38 and E-38-8T.

Information on E-32, E-32 TOU and E-221 will be provided to non-residential customers on aps.com.

e) The copy for the bill messages and written communication that will be provided to customers has not yet been developed.

The monthly residential bill messages will include the following key points:

- On (insert date) APS received approval to increase rates for residential customers by (insert amount). This increase will go into effect on (insert date).
- In addition, APS received authorization to eliminate the service plan you are currently served under.
- APS has five current residential rate plans to meet your needs.
- Please visit aps.com to do a rate comparison to identify which of these rate plans best fit your lifestyle or call 602-371-7171 or 1-800-253-9405 for more information about your available rate options.
- You have until (insert date) to select a new service plan.
- If you have not made a selection by (insert date), you will be automatically transferred to a default service plan.

The commercial bill message will include the following key points:

- On (insert date), APS received approval to increase rates for general service customers by (insert amount). This increase will go into effect on (insert date).
- In addition, APS received authorization to eliminate the service plan you are currently served under.
- E-21, E-22, E-23 and E-24: Effective (insert date) you will be transferred to the General Service TOU (Time of Use) Service Plan, E-32 TOU.
- E-38 and E-38-8T: Effective (insert date) you will be transferred to Water Pumping Service Plan, E-221.
- For information about this service plan, go to aps.com or call 602-371-6766 or 1-800-253-9407.

Residential customers with a frozen rate will be sent a direct mail letter that educates them on the elimination of their rate and the available rate options. The letter will provide a summary overview of the five residential service plans, educate customers on the default rates, encourage customers to complete an on-line rate comparison and provide a phone number for customers to call with questions. The mailing will include a postage-paid business reply card (BRC) to encourage customers to select their new rate.

Customers on E-21, E-22, E-23 and E-24 will be sent a direct mail letter. The direct mail letter will communicate the results of the rate comparison comparing E-32 and E-32 TOU, explain if the customer chooses E-32 a meter change will be required and provide a phone number for customers to call with questions or to request a meter change.

f) The script for the outbound recorded message and the script for customer service personnel who are responding to customer inquiries have not yet been developed. Two outbound recorded message campaigns will be completed. The first campaign will be conducted within six weeks following the approval of the rate case. The first outbound recorded message will inform the customer that the call is an important message from APS, reference the direct mail letter that was sent to residential customers, communicate that if the customer does not select a new rate plan by a certain date they will automatically be transferred to the appropriate default rate and inform the customer if they have questions to call us at 602-371-7171 in the Metro Phoenix area, or 1-800-253-9405 outside Metro Phoenix.

Residential customers will receive a second recorded message one month before residential customers are automatically transferred to the

Exhibit B

APS Revised Schedule 1

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS
REGARDING ARIZONA PUBLIC SERVICE COMPANY RATE CASE
DOCKET NO. E-01345A-05-0816
JULY 18, 2006

EAA 10-4 Referring to your response to EAA 4-10(a), please explain how the proposal to prohibit all master metering for new construction and apartment complexes is not in conflict with the current provision in Commission rule R14-2-205(B)(1) which allows master metering if the building is served by a centralized heating, ventilation or air conditioning system and the contractor can provide to the utility an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship.

SUPPLEMENTAL RESPONSE:

Attached is the revised Service Schedule 1 both clean, APS10671, and redlined, APS10672.

Witness: Greg DeLizio

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.

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/or 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.

2.2 Service Establishment and Customer Request for Special Service 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.

2.2.1 The customer will 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 the point of delivery.

2.2.2 The customer will additionally be required to pay an after-hours charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established after 5:00 p.m. on a day other than the day of request.

2.2.3 The customer will additionally be required to pay a same day connect charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established on the same day the request is being made, and Company agrees to work the request on the same day of the request. This will be charged

regardless of the time the order may be worked by Company on that day. Company may, where no additional costs are incurred by Company, waive the same day fee.

2.2.4 The customer will additionally be required to pay $75.00 per crew person per hour when customer requests services that do not meet the definition of service establishment as defined in A.A.C. R14-2-203.D.3. Customers will be charged for work such as metering equipment installations, including instrument transformers (excluding meters), maintenance or planned outages requested by the Customer, etc. that require the availability of Company employees after hours, on a weekend day, or on a Company holiday. The number of employees utilized by Company in fulfilling such requests shall be at the sole discretion of Company.

Company holidays are New Year's Day, Martin Luther King, Jr. Day, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, The Day After Thanksgiving, and Christmas Day.

2.2.5 Company may waive the service establishment charge where:

2.2.5.1 No field trip is required because applicant accepts responsibility for energy billed and not yet paid and the change is effective with the last meter read and meter read date billed.

2.2.5.2 Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company. This service agreement is for property owners that have established credit with Company and provides for continuous service to the landlord between tenants.

2.2.5.3 Where multiple connects are performed during the same site visit, in the same applicant name, at the same address, for the same class of service, Company will assess the Service Establishment Charge once for every two delivery points.

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 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 2.5 or 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 from the same or a prior service address.

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 from the same or a prior service address.

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 Residential Establishment of Credit or Security Deposit

2.5.1 Establishment of Credit - Company shall not require a security deposit from a new applicant for 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.

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 within six (6) months of the current date which states that the applicant had a timely payment history for the prior twelve (12) consecutive months 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 Credit or 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 non-residential applicants will be required to place a cash deposit to secure payment of bills for service as prescribed herein, unless:

2.5.3.1 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.

2.5.3.2 The applicants provides 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 Establishment or 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 twelve (12) 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 – Once it is determined that a security deposit is required, the following will apply:

2.7.1 Security deposits may be required for each service location.

2.7.2 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by Company in accordance with this section:

2.7.2.1 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,

2.7.2.2 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 Company is providing bundled electric service.

2.7.2.3 If the customer's average consumption increases: by more than ten (10) percent for residential accounts or five (5) percent for nonresidential accounts within a twelve (12) consecutive month period and credit has not been established, an additional security deposit may, at Company's option, be required.

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 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 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 receiving bundled service, Company will use reasonable care in initially establishing service to the customer under the most advantageous 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 Optional Rates – Certain optional 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. Billing under the alternate rate will become effective from the next regularly scheduled meter reading, after 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 service 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 that selects Direct Access service 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 service 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 service.

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, at customer's request, 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 fiftteen (15) calendar days from the billing date. Any payment not received within this time frame will 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 charges. 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 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.

4.3.2.1 Refunds to customers resulting from overbillings will be made promptly upon discovery by Company.

4.3.2.2 Corrected charges for underbillings 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

4.3.2.3 Except as specified below, corrected charges for underbillings shall be limited to three (3) month for residential accounts and six (6) months for non-residential accounts.

4.3.2.3.1 Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with the contract or rate schedule requirements and is not limited to three or six months as applicable.

4.3.2.3.2 Where service has been established but no bills have been rendered, corrected charges for underbillings shall go back to the date service was established.

4.3.2.3.3 Where there is evidence of meter tampering or energy diversions, corrected charges for underbillings shall go back to the date meter tampering or energy diversions began, as determined by Company.

4.3.2.3.4 Where lack of access to the meter (caused by the customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the billing month of the last actual Company obtained meter read date.

4.3.2.4 Company may forgo billing and collection of corrected charges for an underbilling if Company believes the cost of billing and collecting the underbilling would not justify pursuing the underbill.

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 or cashier's check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer will 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 Termination Process Charges

4.5.1 Company will require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the customer's site to accept payment on 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.

4.5.2 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.

4.5.3 To avoid termination of service, the customer will 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 will 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 whether the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service to the designated point of delivery, as specified in Section 6.3 of this Schedule, 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. Company may deliver service for special applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

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 satisfactory 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 satisfactory unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any rate options where, in Company's opinion, 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 plus the cost incurred to install the specialized meter as a one-time charge and any reoccurring incremental costs. 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 an extension to serve a customer, which is either on sites 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 granted to, or 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 ensure 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. Customer shall meet power factor requirements as specified on applicable rate schedules.

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.asp.

6.1.2 Where a customer requests, and Company approves of, a special meter reading device or communications services or devices to accommodate the customer's needs, the cost for such additional equipment and usage fees 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 result in charge to the MSP of the replacement costs, plus an administration fee of fifteen percent (15%), less five (5) years depreciation.

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 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. If Company must temporarily replace the MSP's meter and/or associated metering equipment 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.

6.3.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.

6.3.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development'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.

6.3.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, Company and customer shall mutually agree upon the designated point of delivery.

6.3.4 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 Company issued identification 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 energy and, if applicable, demand is estimated by Company, estimation will be in accordance with Company's bill estimation procedures approved by the Arizona Corporation Commission. 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 and, if applicable, demand, for the period in which the energy eversion took place. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer will 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.

6.4.3.1 Customer will be billed, in accordance with Section 4.3.2, for the estimated energy and demand that would have registered had the meter been operating properly.

6.4.4 Where Company is the MRSP, Company will, 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, at its option, 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 - 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. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.6.3 Multi-Unit Residential High Rise Developments – Company will allow master metering for high rise residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.6.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.6.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

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.

7.1.9 Company learns of the existence of any condition in Section 2.4, Grounds For Refusal of Service.

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.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS
REGARDING ARIZONA PUBLIC SERVICE COMPANY RATE CASE
DOCKET NO. E-01345A-05-0816
JULY 18, 2006

EAA 10-4 Referring to your response to EAA 4-10(a), please explain how the proposal to prohibit all master metering for new construction and apartment complexes is not in conflict with the current provision in Commission rule R14-2-205(B)(1) which allows master metering if the building is served by a centralized heating, ventilation or air conditioning system and the contractor can provide to the utility an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship.

SUPPLEMENTAL RESPONSE:

Attached is the revised Service Schedule 1, APS10679, redlined, indicating changes from the current approved Schedule 1.

Witness: Greg DeLizio

SERVICE 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/or 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 and Customer Request for Special Service 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~~will 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~~the point of delivery.

2.2.2 The customer ~~may~~will additionally be required to pay an after-hours charge of $75.00 ~~should~~if the customer requests 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,~~after 5:00 p.m. on a day other than the day of request.

2.2.3 The customer will additionally be required to pay a same day connect charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established on the same day the request is being made, and Company agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by Company~~.~~ on that day. Company may, where no additional costs are incurred by Company, waive the same day fee.

2.2.4 The customer will additionally be required to pay $75.00 per crew person per hour when customer requests services that do not meet the definition of service establishment as defined in A.A.C. R14-2-203.D.3. Customers will be charged for work ~~(~~such as metering equipment installations, including ~~which include~~ instrument transformers (excluding meters), maintenance or planned outages requested by the Customer, etc.) that require the availability of Company employees after hours, on a weekend day, or on a Company holiday. The number of employees utilized by Company in fulfilling such requests shall be at the sole discretion of Company.

Company holidays are New Year's Day, Martin Luther King, Jr. Day, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, The Day After Thanksgiving, and Christmas Day.

2.2.5 Company may waive the service establishment charge where:

2.2.5.1 No field trip is required because applicant accepts responsibility for energy billed and not yet paid and the change is effective with the last meter read and meter read date billed.

2.2.5.2 Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company. This service agreement is for property owners that have established credit with Company and provides for continuous service to the landlord between tenants.

~~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.~~

2.2.5.3 Where multiple connects are performed during the same site visit, in the same applicant name, at the same address, for the same class of service, Company will assess the Service Establishment Charge once for every two delivery points.

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 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 2.5 or 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 from the same or a prior service address.

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 from the same or a prior service address.

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 Residential Establishment of Credit or Security Deposit

2.5.1 Establishment of Credit - Company shall not require a security deposit from a new applicant for 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 within six (6) months of the current date which states that the applicant had a timely payment history for the prior twelve (12) consecutive months 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 Credit or 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~~ All non-residential applicants will be required to~~:2.5.3.1 Place~~ place a cash deposit to secure payment of bills for service as prescribed herein, ~~or~~unless:

2.5.3.1 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.

2.5.3.2 ~~Provide~~The applicant provides 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 ~~E~~Reestablishment or 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 twelve (12) 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 – Once it is determined that a security deposit is required, the following will apply:

2.7.1 Security deposits may be required for each service location.

2.7.2 ~~2.7.1~~ Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by ~~the~~ Company in accordance with this section:

~~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,~~

2.7.2.1 ~~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,

2.7.2.2 ~~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~~Company is providing bundled electric service.

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

2.7.2.3 If the customer's average consumption increases: by more than ten (10) percent for residential accounts or five (5) percent for nonresidential accounts within a twelve (12) consecutive month period and credit has not been established, an additional security deposit may, at Company's option, be required.

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 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~~receiving bundled service, 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 regularly scheduled meter reading, ~~or when~~after 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~~service 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~~that selects Direct Access ~~rate selection~~service 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 service 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 service.

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, at customer's request, 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~~~~nineteen (15~~19) fifteen (15) calendar days from the billing date. Any payment not received within this time frame ~~shall~~will 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~~charges. 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.~~

4.3.2.1 Refunds to customers resulting from overbillings will be made promptly upon discovery by Company.

4.3.2.2 Corrected charges for underbillings 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

4.3.2.3 Except as specified below, corrected charges for underbillings shall be limited to three (3) month for residential accounts and six (6) months for non-residential accounts.

4.3.2.3.1 Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with the contract or rate schedule requirements and is not limited to three or six months as applicable.

4.3.2.3.2 Where service has been established but no bills have been rendered, corrected charges for underbillings shall go back to the date service was established.

4.3.2.3.3 Where there is evidence of meter tampering or energy diversions, corrected charges for underbillings shall go back to the date meter tampering or energy diversions began, as determined by Company.

~~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.~~

4.3.2.3.4 Where lack of access to the meter (caused by the customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the billing month of the last actual Company obtained meter read date.

~~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.~~

4.3.2.4 Company may forgo billing and collection of corrected charges for an underbilling if Company believes the cost of billing and collecting the underbilling would not justify pursuing the underbill.

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 or cashier's check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer ~~shall~~will 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 Termination Process Charges

4.5.1 ~~4.5 Field Call Charge~~ Company ~~may~~will 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~~on 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~~4.5.2 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.

4.5.3 ~~4.5.2~~ To avoid termination of service, the customer ~~may~~will 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~~will 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~~whether the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service to the designated point of delivery, as specified in Section 6.3 of this Schedule, 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. Company may deliver service for special applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

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 satisfactory 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 satisfactory unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any ~~existing~~ rate options where, in Company's opinion, 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 plus~~and~~ the cost incurred to install the specialized meter as a one-time charge and any reoccurring incremental costs. 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~~an extension to serve a customer, which is either on sites 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 granted to, or 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~~ensure 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~~Customer shall meet power factor requirements as specified on applicable rate schedules.

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.asp.

~~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.~~

6.1.2 ~~6.1.3~~ Where a customer requests, and Company approves of, a special meter reading device or communications services or devices to accommodate the customer's needs, the cost for such additional equipment and usage fees 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~~result in charge to the MSP of the replacement costs ~~less five (5) years depreciation,~~ plus an administration fee of fifteen percent (15%), less five (5) years depreciation.

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 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~~If 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.

6.3.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.

6.3.2 ~~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 or development'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~~

6.3.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, Company and customer shall mutually agree upon the designated point of delivery.

6.3.4 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 Company issued identification 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.~~10). Where energy and, if applicable, demand is estimated by Company, estimation will be in accordance with Company's bill estimation procedures approved by ~~Schedule 8, Bill Estimation, as filed with~~ the Arizona Corporation Commission. 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~~and, if applicable, demand, for the period in which the energy eversion took place.~~that would have registered had all energy and demand usage been properly metered.~~ Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer ~~may~~will 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.

6.4.3.1 ~~6.4.4 Customer will be billed~~Customer will be billed, in accordance with Section 4.3.2, for the estimated energy and demand that would have registered had the meter been operating properly.

6.4.4 Where Company is the MRSP, Company ~~shall~~will, 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, at its option, 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.~~ 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. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.6.3 Multi-Unit Residential High Rise Developments – Company will allow master metering for high rise residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.6.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.6.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

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.

7.1.9 Company learns of the existence of any condition in Section 2.4, Grounds For Refusal of Service.

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.

Exhibit C

APS Revised Schedule 3

ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS
REGARDING ARIZONA PUBLIC SERVICE COMPANY RATE CASE
DOCKET NO. E-01345A-05-0816
JULY 12, 2006

EAA 7-4 For each category of development, please identify the specific subsection of Section 4, Refunds, that would apply to each category. For instance, Section 1.2.3 of the proposed tariff for Residential Homebuilder Subdivisions refers to the refund provisions in Section 4. Please provide the specific refund methodology that would be applicable in Section 4.

Supplemental Response:

Attached is the revised Service Schedule 3 both clean, APS10683, and redlined, APS10684.

Witness: David Rumolo

SERVICE 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 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 as determined by Company.

The following policy governs the extension of overhead and underground electric facilities rated up to 21kV to customers whose requirements are deemed by Company to be usual and reasonable in nature.

DEFINITIONS

a. Backbone Infrastructure means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

b. Conduit Only Designs mean a line extension request where the developer is only requesting the conduit layout and design to serve the project. Local distribution facilities such as transformers and services will be installed at a later date when lot sales occur.

c. Corporate Business & Industrial Developments means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial and/or industrial use.

d. High Rise Residential means residential multi-family developments built with four or more floors, usually using elevators for accessing floors.

e. Irrigation means water pumping service. Agricultural pumping means water pumping for farms and farm-related pumping used to grow commercial crops or crop-related activity. Non-agricultural water pumping is pumping for purposes other than the growing of commercial crops, such as golf course irrigation or municipal water wells.

f. Master Planned Community Developments means developments that consist of a number of separately subdivided parecels for different "Residential Homebuilder Subdivisions". Develpments may have a variety of uses including residential, commercial, and public use facilities.

g. Mixed Use Residential Developments means buildings that consist of both residential and commercial use, such as a high-rise building where the first level is for commercial purposes and the upper floors are residential.

h. Residential Custom Home "Lot Sale" Developments means any tract of land which has been divided into six or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home.

i. Residential Homebuilder Subdivisions means any tract of land which has been divided into six or more contiguous lots in which the developer is responsible for the construction of residential homes or permanent mobile home sites.

j. Residential Multi-family Developments means developments consisting of apartments, condominiums,or townhouse developments.

k. Residential Single Family means a house, an apartment, or a mobile home permanently affixed to a lot or site.

l. System Improvement Costs means the costs of system additions over and above what is required to serve the customer, where such additions provide additional capacity for other customers.

1. RESIDENTIAL

1.1 SINGLE FAMILY HOMES

1.1.1 Residential extensions will be made to new permanent residential customers or groups of new permanent residential customers. For purposes of this section, a "group" shall be defined as five or less homes. An allowance of $5,000 per lot will be credited against the total construction cost, as determined by Company. Any additional cost will be paid by the applicant, as a refundable advance prior to Company extending facilities.

1.1.2 Where an advance is required, Company will issue the applicant an Advance Certificate. If, within five (5) years of issuance, a lateral extension is made off the original line extension, the applicant may present his/her Advance Certificate to Company for a potential refund. Refunds will be issued when the Advance Certificate is presented for payment and the connection of the subsequent applicant has been verified. In no event will refunds exceed the original advance. Refunds will be determined as shown in the example:

EXAMPLE:

First applicant's estimated cost for a line extension	$22,000
First applicant allowance	$ 5,000
First applicant's advance	$17,000
Second applicant's estimated cost for a lateral off the original extension	$ 3,000
Second applicant's allowance	$ 5,000
Refund to first applicant upon presentation of Advance Certificate and verification	$ 2,000

1.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

1.2.1 Extensions will be made to residential subdivision developments of six or more homes in advance of application for service by permanent customers provided the applicant(s) signs an extension agreement. If approved by Company, a per lot allowance of $5,000 may be credited against the total construction cost, which costs may include applicable backbone system costs as determined by Company as determined by Company (minus street light and system improvement costs). Any

additional construction cost in excess of the per lot allowance will be paid by applicant as a non-refundable contribution in aid of construction.

1.2.2 Company reserves the right to perform a field audit as to the number of permanently connected customers within the development eighteen (18) months from the extension agreement's execution date and requires the applicant to make a refundable advance of the construction costs less the applicable credit for the number of permanently connected customers to date.

1.2.3 Company reserves the right to disallow the allowance and collect a full advance of the construction costs from the applicant based on the project scope, or location, or financial condition of the applicant, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.2.

1.2.4 The following provides examples of the application of the policy:

EXAMPLE 1:

The following example illustrates a case in which the allowance is adequate to cover the subdivision's construction costs. It is assumed that the developer sells all of the homes in the 18 month period.

Estimated Construction Cost	$450,000
Number of Homes	100
Total Allowance	$500,000
Non-Refundable Contribution	$ 0

EXAMPLE 2:

Example #2 illustrates a case in which the construction costs exceed the allowance and the developer completes all homes in the subdivision. The total construction cost exceeds the allowance by $150,000 and the developer provides the non-refundable contribution in aid of construction when the extension agreement is executed. Since the developer completes all 100 homes within the 18 month period after the execution date of the extension agreement, no additional funds are advanced by the developer.

Estimated Construction Cost	$650,000
Number of Homes	100
Total Allowance	$500,000
Non-Refundable Contribution	$150,000

EXAMPLE 3:

The following example illustrates a case in which two events accur. First, the allowance does not adequately cover the required construction. This results in the requirement that the developer provide a non-refundable contribution in aid of

construction. This payment is due at the time the extension agreement is signed by the developer.

The second event illustrated in this example is the developer does not sell sufficient homes in the development in the 18 month period following the extension agreement execution date. In the example, at the end of the 18 month period, the developer has completed 35 homes. Since there are 65 homes left to be completed the developer must provide a refundable advance of $325,000. This advance will be refunded during the subsequent 42 months as additional homes are completed. Any un-refunded advance remaining at the end of the refund period becomes a non-refundable contribution in aid of construction.

Estimated Construction Cost	$650,000
Number of Homes Planned	100
Potential Allowance Refundable Advance	$500,000
Non Refundable Contribution	$150,000
Assume Number of Completed Homes	35
Allowance Credited (35 x $5000)	$175,000
Potential Amount Remaining Eligible For Refund	$325,000

1.3 RESIDENTIAL CUSTOM HOME "LOT SALE" DEVELOPMENTS

Extensions will be made to residential "lot sale" custom home developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement and make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure. The advance should be provided at the time the extension agreement is executed.

1.3.1 Line extensions and/or equipment installations will be made for each permanent customer upon request for service, and the cost of the installation along with the cost for the "backbone" infrastructure will be used in determining the cost for the development. A per completed home allowance of $5,000 will be credited against the construction cost as determined by Company (minus streetlight and system improvements costs). Any additional construction cost will be paid as a non-refundable contribution in aid of construction.

1.3.2 Company reserves the right to disallow the allowance and collect a full advance of the construction costs from the applicant(s) based on the project scope, or location, or financial condition of the applicant(s), or where organizational structure of the applicant(s) warrants, as determined by Company. Advances are subject to refund as specified in Section 4.2.

1.3.3 Company will provide "conduit only" designs provided applicant makes a non-refundable contribution in aid of construction in the amount equal to the estimated cost of preparation, in addition to the costs for any field survey and inspections that may be required.

1.3.4 The examples provided in 1.2.4 would also be applicable to "lot sale" developments.

1.4 MASTER PLANNED COMMUNITY DEVELOPMENTS

Extensions will be made to master planned community developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement and make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure.

1.4.1 Line extensions and equipment installation for backbone infrastructure to serve a Master Planned Development will be made in advance of application for service by permanent customers. A per lot allowance of $1,000 may be credited against the backbone infrastructure cost as determined by Company (minus street light and system improvement costs). Any additional cost will be paid by applicant as a non-refundable contribution.

Line extensions and equipment installations will be made for each residential subdivision within the planned development in advance of application for service by permanent customers. The cost of the extensions and equipment installations needed to provide service will be used in determining the cost for the development. A per lot allowance of $4,000 will be credited against the "subdivision" cost as determined by Company (minus street light and system improvement costs). Any additional cost will be paid as a non-refundable contribution in aid of construction.

1.4.2 Company reserves the right to disallow the credit and collect a full advance of the construction costs from the applicant based on the project scope, or location, or financial condition of the applicant, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.

1.4.3 The residential extension examples provided in 1.2.4 would be applicable to residential developments within a Master Planned Community. Extensions to multi-family developments or commercial developments would be made in accordance with the applicable sections of this Service Schedule. The following example illustrates the policy application for the entire project.

EXAMPLE 4:

Example #4 illustrates a case in which the developer of the Master Planned Community requests an extension of backbone infrastructure and individual residential developers request extensions for residential subdivisions. The developer makes a refundable contribution in aid of construction at the time the extension agreement is executed. The individual subdivision will be handled in a manner consistent with the subdivision examples found in Section 1.2.4.

Estimated Backbone Cost	$2,500,000
Number of Homes	1000
Potential Allowance Refundable Advance	$1,000,000
Non Refundable Contribution	$1,500,000
Estimated Subdivision Cost	$600,000
Number of Homes	200
Total Allowance	$800,000
Non-Refundable Contribution	$0

1.5 RESIDENTIAL MULTI-FAMILY DEVELOPMENTS

1.5.1 Extensions will be made to multi-family apartment, condominium or townhouse developments in advance of application for service by permanent customers. If approved by Company, a per completed unit allowance of $500 may be credited against the total construction cost, including any applicable backbone infrastructure costs as determined by the company, (minus street light and system improvement costs). Any additional cost will be paid as a non-refundable contribution in aid of construction.

1.5.2 Company reserves the right to perform a field audit as to the number of permanently connected customers within the development eighteen (18) months from the extension agreement's execution date and requires the applicant to make a refundable advance of the construction costs less the applicable credit for the number of permanently connected customers to date.

1.5.3 Company reserves the right to disallow the credit and collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.

1.6 HIGH RISE AND MIXED USE RESIDENTIAL DEVELOPMENTS

1.6.1 Extensions will be made to high rise and mixed use developments where the residential units are privately owned and either individually metered or master metered in accordance with Section 6.12.3.

1.6.2 In general, APS will provide service to these type of developments at one point of delivery and it is the developer's responsibility to provide and maintain the electrical distribution facilities within the building.

1.6.3 Extensions will be on the basis of Economic Feasibility. "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(s) and development.

1.6.4 Company reserves the right to collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.2.

2. NON-RESIDENTIAL

2.1 General service line extensions and equipment installations will be made to all applicants not meeting the definition of Residential or as provided for in Section 2.4, or Section 3 of this Schedule. General service line extensions and equipment installations will be made on the basis of Economic Feasibility or on a revenue basis as described in Section 2.2. "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. Extensions that are economically feasible as determined by the revenue basis as described in Section 2.2 or by the economic feasibility analysis described in this section are provided free to the customer. Extensions will be provided to customers that do not meet the economic feasibility determination provided the customer signs an extension agreement and advances as much of the construction cost and/or agree to pay a facilities charge to make the extension economically feasible. Advances are subject to the refund provisions of Section 4.

2.2 A revenue basis extension will be made to customers or applicants except those specified in Sections 2.4; 3.1; 3.2; or 3.3; when the extension does not exceed a total construction cost of $25,000.

2.2.1 Such extension shall be free to the customer where 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 Company reserves the right to collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.

2.4 CORPORATE BUSINESS & INDUSTRIAL PARK DEVELOPMENTS

2.4.1 Extensions will be made to business and industrial park developments in advance of application for service by permanent customers, provided applicant(s) make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure.

2.4.2 The costs for the installed infrastructure and the cost of the extensions and equipment installations needed to provide service to each permanent customer will be used in determining the developments Economic Feasibility. "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(s) and development.

2.4.3 For extensions and equipment installations which meet the conditions specified in Section 2.4.1, Company, after special study and at its option, may install its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 2.1, provided such customers or applicant(s) sign an extension agreement and advance as much of the construction cost and/or pay a non-refundable contribution (facilities charge) to make the extension economically feasible. Advances are subject to refund as specified in Section 4.1.

3. OTHER CONDITIONS

3.1 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 4.3. Non-agricultural irrigation pumping service to permanent customers will be extended as specified in Section 2. Non-agricultural irrigation pumping service to temporary or doubtful permanency customers will be extended as specified in Section 3.2 or 3.3 below, as applicable.

3.2 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.

3.3 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 4.4.

4. REFUNDS

4.1 ECONOMIC FEASIBILITY BASIS REFUNDS

Customer advances over $50.00 are subject to full or partial refund. At the end of eighteen months from the date Company facilities are energized, Company will obtain actual closing costs and actual first year distribution revenues and determine if the company is receiving the required minimum rate of return. If this results in an advance lower than the amount advanced by customer, Company will refund the difference between the amount advanced and the amount that would have been advanced using actual closing costs and distribution revenues. In no event shall the amount of any refund exceed the amount originally advanced. Subsequent refund studies will be performed at one year intervals for an additional four years using actual distribution revenues for the year. At the end of this total five year refund period, any advance not refunded shall become a nonrefundable contribution in aid of

construction.

4.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

Customer advances over $50.00 are subject to refund based on the number of permanently connected customers during the five year refund period commencing on the extension agreement's execution date. At the end of this total five year refund period, any advance not refunded shall become a nonrefundable contribution in aid of construction.

4.3 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.

4.4 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances over $50.00 are subject to full or partial based on the Economic Feasibility Basis as specified in Section 3.3. 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.

4.5. GENERAL REFUND CONDITIONS

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

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

4.5.3 Any unrefunded advance balance shall become nonrefundable five (5) years from the execution or the effective date of the agreement.

4.5.4 Company reserves the right to withhold refunds to any customer or developer who is delinquent on any account, agreement, or invoice and apply these refund amounts to past due bills.

5. UNDERGROUND CONSTRUCTION

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

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

5.1.2 The customer or applicant(s) provides all earthwork including, but not limited to, trench, boring or punching, backfill, compaction, and surface restoration in

accordance with Company specifications.

5.1.3 The customer or applicant(s) provides installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications.

5.1.4 In lieu of customer or applicant(s) providing these services and equipment, the company may provide and the customer or applicant(s) will make a non-refundable contribution equal to the cost of such work plus any administrative or inspection fees incurred by Company. Customers or applicants electing this option will be required to sign an agreement indemnifying and holding APS harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than APS' contractors, which claims arise out of the trenching and conduit placement, provided the claims are not attributable to APS' gross negligence or intentional misconduct.

5.2 Where it is determined that three phase service is required to serve the customer, Customer may be required to make 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. GENERAL CONDITIONS

6.1 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. Company may deliver service for special applications of higher voltages with prior approval from Company's Engineering Department and in accordance with this Schedule.

6.2 POINT OF DELIVERY

6.2.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.

6.2.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinets necessary for the installation of Company's underground service conductors.

6.2.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, APS and customer shall mutually agree upon the designated point of delivery.

6.3 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.

6.4 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.

6.5 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.

6.6 OWNERSHIP

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

6.7 MEASUREMENT AND LOCATION

6.7.1 Measurement must be along the proposed route of construction.

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

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

6.8 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.

6.9 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.

6.10 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.

6.11 RELOCATIONS AND/OR CONVERSIONS

6.11.1 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.

6.11.2 When the relocation of Company facilities involve "prior rights" conditions, the customer will be required to make a non-refundable contribution equal to the total cost of relocation.

6.11.3 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.

6.12 MASTER METERING

6.12.1 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.

6.12.2 Residential Apartment Complexes, Condominiums - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Corporation Commission's Rules and Regulations or the requirements discussed in 6.12.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.12.3 Multi-Unit Residential Developments – Company will allow master metering for residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.12.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.12.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

6.12.4 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 the basis specified in Section 1.

6.13 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.

6.14 STUDY AND DESIGN DEPOSIT

Any applicant requesting Company to prepare special studies or 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.

6.15 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.

6.16 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.

6.17 INTEREST

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

6.18 EXTENSION AGREEMENTS

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

6.19 ADDITIONAL PRIMARY FEED

When specifically requested by the customer to provide an alternate primary feed (excluding transformation), Company will perform a special study to determine the requests feasibility and the customer may be required to pay a nonrefundable contribution in aid of construction for the added cost as well as the applicable rate for the additional feed requested.

EXHIBIT
S-23
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
BARRY WONG
Commissioner

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 TO AMEND DECISION NO. 67744.	)	DOCKET NO. E-01345A-05-0816 E-01345A-05-0826 E-01345A-05-0827

SURREBUTTAL

TESTIMONY

OF

ERINN A. ANDREASEN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEMBER 27, 2006

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NOS. E-01345A-05-0816 ET AL

Ms. Andreasen's testimony recommends the rate design to be adopted by the Commission for ET-2 incorporate off-peak winter rates that are less than off-peak summer rates. Ms. Andreasen's testimony also addresses Staff's recommended changes to Schedule 1 and Schedule 3.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Erinn Andreasen. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony on the topics of revenue allocations and rate design, APS' proposed customer transition plan, APS' proposed changes to Schedule 1 and Schedule 3, general issues related to the establishment of hook-up fees, and demand-response and load-management programs.

Q. What is the scope of your rebuttal testimony in this proceeding?

A. My rebuttal testimony will address rate schedule ET-2, Schedule 1, and Schedule 3.

RATE SCHEDULE ET-2

Q. Does Staff have any comments regarding the revenue neutrality of the proposed rate design for ET-2 that was provided in its direct testimony?

A. Yes. ET-2 is a recently approved time-of-use rate that has an on-peak period from 12:00 p.m. to 7:00 p.m.[1] Based on further evaluation, Staff has determined that if Staff's proposed rates for ET-2 are adopted by the Commission an adjustment should be made for revenue neutrality when compared to ET-1.

[1] Approved in Commission Decision No. 68645.

Q. Does Staff have any other recommendations regarding the rate structure for ET-2?

A. Yes. Under the current rate structure, the off-peak kilowatt-hour ("kWh") charge for the winter season is higher than the off-peak kWh charge for the summer season. Typically, a utility's generating costs are lower in the winter than they are in the summer which is not reflected in the design of the current rate structure. Therefore, Staff recommends that the rate design to be adopted by the Commission for ET-2 incorporate off-peak winter rates that are less than off-peak summer rates.

SCHEDULE 1

Q. Has Staff reviewed APS' revised Schedule 1?

A. Yes. APS provided a redlined and clean copy of Schedule 1 in the Rebuttal testimony of Mr. Greg Delizio.

Q. What does Staff recommend in regard to Schedule 1?

A. Although Mr. Delizio does not explain the changes that were made to the latest version of Schedule 1,[2] in his rebuttal testimony, Staff believes that APS made modifications to sections 4.3.2.3.4, 5.4, and 6.4 of Schedule 1. Staff recommends that the wording for sections 4.3.2.3.4, 5.4, and 6.4 on Schedule 1 included on APS document number 10679 be adopted. Copies of the wording in the applicable section are attached as Exhibit A. Staff also reasserts its recommendation included in direct testimony that APS include a definition for Multi-Unit Residential High-Rise Developments on Schedule 1.

[2] APS document number 10679 which can be found in the direct testimony of Staff witness Ms. Erinn Andreasen.

SCHEDULE 3

Q. Has Staff reviewed APS' revised Schedule 3?

A. Yes. APS provided a redlined and clean copy of Schedule 3 in the Rebuttal testimony of Mr. David Rumolo.

Q. What does Staff recommend in regard to schedule 3?

A. Staff recommends that the following clarifying changes to Schedule 3 be adopted.

a. Clarify that under section 1.1.1 of Schedule 3, "group" would be defined as "4 or less homes" instead of "less than 4 homes."

b. Clarify that under section 1.3.1 of Schedule 3, the allowance would be credited against the "total construction costs."

c. Clarify that under section 1.3.2 of Schedule 3, advances would be subject to refund as specified in "section 4.1" instead of "section 4.2."

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please provide a summary of your recommendations.

A. 1. Staff recommends that the rate design to be adopted by the Commission for ET-2 incorporate off-peak winter rates that are less than off-peak summer rates.

2. Staff recommends that the wording for sections 4.3.2.3.4, 5.4, and 6.4 on Schedule 1 included on APS document number 10679 be adopted. Staff also reasserts its recommendation included in direct testimony that APS include a definition for Multi-Unit Residential High-Rise Developments on Schedule 1.

3. Staff recommends that the following clarifying changes to Schedule 3 be adopted.

a. Clarify that under section 1.1.1 of Schedule 3, "group" would be defined as "4 or less homes" instead of "less than 4 homes."

b. Clarify that under section 1.3.1 of Schedule 3, the allowance would be credited against the "total construction costs."

c. Clarify that under section 1.3.2 of Schedule 3, advances would be subject to refund as specified in "section 4.1" instead of "section 4.2."

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Exhibit A

4.3.2.3 Except as specified below, corrected charges for underbillings shall be limited to three (3) month for residential accounts and six (6) months for non-residential accounts.

4.3.2.3.1 Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with the contract or rate schedule requirements and is not limited to three or six months as applicable.

4.3.2.3.2 Where service has been established but no bills have been rendered, corrected charges for underbillings shall go back to the date service was established.

4.3.2.3.3 Where there is evidence of meter tampering or energy diversions, corrected charges for underbillings shall go back to the date meter tampering or energy diversions began, as determined by Company.

~~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.~~

4.3.2.3.4 Where lack of access to the meter (caused by the customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the billing month of the last actual Company obtained meter read date.

~~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.~~

4.3.2.4 Company may forgo billing and collection of corrected charges for an underbilling if Company believes the cost of billing and collecting the underbilling would not justify pursuing the underbill.

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 or cashier's check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer ~~shall~~will 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.

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 satisfactory 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 satisfactory unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any ~~existing~~ rate options where, in Company's opinion, 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 plus~~and~~ the cost incurred to install the specialized meter as a one-time charge and any reoccurring incremental costs. 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~~an extension to serve a customer, which is either on sites 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 granted to, or 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

~~permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry credentials~~

6.3.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, Company and customer shall mutually agree upon the designated point of delivery.

6.3.4 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 Company issued identification 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.~~10). Where energy and, if applicable, demand is estimated by Company, estimation will be in accordance with Company's bill estimation procedures approved by ~~Schedule 8, Bill Estimation, as filed with the~~ Arizona Corporation Commission. 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~~and, if applicable, demand, for the period in which the energy eversion took place. ~~that would have registered had all energy and demand usage been properly metered.~~ Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer ~~may~~will 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.

6.4.3.1 ~~6.4.4 Customer will be billed~~Customer will be billed, in accordance with Section 4.3.2, for the estimated energy and demand that would have registered had the meter been operating properly.

6.4.4 Where Company is the MRSP, Company ~~shall~~will, 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

EXHIBIT
S-24
admitted

PREM K. BAHL

Work Experience

Mr. Prem Bahl worked at the Arizona Corporation Commission from 1988 to 1998 as a Utilities Consultant, and has been re-employed at the Commission as an Electric Utilities Engineer since June 2002. During this time period of over fourteen years, Mr. Bahl conducted engineering evaluations of jurisdictional electric utility rate cases and financing cases. He inspected the utility power plants including the Palo Verde Nuclear Generating Station, and transmission and distribution systems. Mr. Bahl was involved with the development of retail competition in Arizona and of DesertStar, an Independent System Operator ("ISO") for the desert southwest region. He was Chairman of the Commission System Reliability Working Group, which evaluated the impact of competition on system reliability and was instrumental in recommending the establishment of the Arizona Independent System Administrator ("AISA") as an interim organization until commercial operation of DesertStar, which later evolved as WestConnect, a Regional Transmission Operator ("RTO"). Since rejoining the Commission, Mr. Bahl has reviewed the utilities' load curtailment plans; and coordinated with the Commission Consultants to hold workshops to report on the second, third, and fourth Biennial Transmission Assessments for the state of Arizona.

During the 2002-2006 period, Mr. Bahl testified in the line siting cases of Tucson Electric Power Company's ("TEP") 138 kV Robert Bills-Wilmont Substation and Trico Electric Cooperative's 115 kV Sandario Project. He is also responsible for ensuring compliance of conditions put forth in the Certificates of Environmental Compatibility issued to merchant plants including, among others, Harquahala, Panda Gila River, Mesquite, Duke

Arlington Valley, and Red Hawk power plants and compliance of conditions relative to utilities' transmission lines.

From July 1998 to August 2000, Mr. Bahl worked as Chief Engineer at the Arizona State Residential Utility Consumer Office ("RUCO"). During this time period, he performed many of the duties he performed at the Commission. Mr. Bahl was also involved with the Distributed Generation Work Group that looked at the impact of development of distributed generation in Arizona on system reliability, and modifications of interconnection standards currently specified by the jurisdictional utilities. He was a member of the AISA Board of Directors from September 1999 until June 2000. He was involved in the deliberations of the Market Interface Committee of the North American Electric Reliability Council ("NERC"). Mr. Bahl also published and presented a number of technical papers at national and international conferences regarding transmission issues and distributed generation during the last twenty five years.

Prior to his employment with the Commission, Mr. Bahl had worked as an electrical engineer with electric utilities and consulting firms in the transmission and generation planning areas for approximately thirty years, including ten years experience at the Punjab State Electricity Board ("PSEB") in India from 1960 to 1970. He was Executive Engineer at the PSEB from 1968 to 1970 prior to coming to the United States in 1970.

Educational Background

Mr. Bahl graduated from the South Dakota State University with a Masters degree in Electrical Engineering in May 1972. He received his Professional Engineering ("P.E.") License in the state of Arizona in 1978. His Bachelor of Science degree in Electrical Engineering was from the Agra University, India, in 1957.

EXHIBIT
S-25
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
BARRY WONG
Commissioner

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, AND TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	DOCKET NO. E-01345A-05-0816

DIRECT

TESTIMONY

OF

JERRY D. SMITH

ELECTRIC UTILITY ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 18, 2006

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

This testimony and the attached exhibits provide an analysis of the quality of service provided by APS for calendar years 2000 through 2005. It also provides a used and useful determination regarding capital improvements made in the rate case test year: 2005.

During the period of this quality of service assessment, APS experienced several transmission outages that resulted in interruption of service to distribution customers. In each instance APS notified and informed the Commission of its action and how it was managing restoration of service to customers. The scope of system improvements since the Westwing and Deer Valley Substation fires is vast and impressive to observe in the field. Major capital improvements have been made to remedy and mitigate the causes and effects of these events and to preclude a reoccurrence. Damaged equipment has been replaced and Type U transformer bushings are being replaced through out the APS system. Single points of failure for protection and control systems have been eliminated, fire mitigation measures have been implemented at various substations, and fire wall and oil cache basins are being established at appropriate substations.

The Summer 2004 transmission outages and Westwing and Deer Valley fires also have yielded positive effects for Arizona consumers. APS has implemented EPRISolutions, Inc. recommendations regarding 14 areas of maintenance and repair practices. As a consequence APS formed a Predictive Maintenance Team to focus on predictive and preventative maintenance activities to find and repair equipment prior to failure. APS has proactively resolved a significant number of equipment problems by using these diagnostic tools and intensifying its maintenance practices. Improved service to future generations of customers is more likely to occur as a result of these efforts.

All newly constructed and improved facilities observed during Engineering's site visits were found to be in compliance with NESC requirements. Sites that were visited that had capital improvements reported by APS for 2005 test year purposes were found to actually have been constructed and were operational. A sufficient sample of 2005 improvements were observed in the field and suggests a "used and useful" determination for 2005 test year capital improvements is warranted.

Engineering finds no reason to recommend consideration of quality of service mitigation measures as part of the pending APS rate case. However, Engineering does recommend that the Commission continue to monitor APS' quality of service as an integral part of required Biennial Transmission Assessments, through the Commission's existing outage reporting requirements, and via ongoing resolution of consumer complaints about APS service. Engineering further suggests that the Commission be particularly mindful of quality of service differences between the APS Metro Division and more rural service oriented APS divisions. It is for this reason that quality of service to the APS Southeast Division merits special scrutiny to assure service does not deteriorate and become problematic.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Jerry D. Smith. I am an Electric Utility Engineer employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background.

A. I graduated from the University of New Mexico in 1968 with a Bachelor of Science degree in Electrical Engineering. I received a Masters of Science degree in Electrical Engineering from New Mexico State University in 1977 majoring in power systems and electric utility management.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

Q. Briefly describe your responsibilities as an Electric Utility Engineer.

A. I joined the Commission's Utilities Division Staff as an electric engineer in 1999. In my capacity as an Electric Utility Engineer, I have investigated the quality of service provided by electric utilities in Arizona and been responsible for three biennial transmission assessments regarding the reliability of existing and planned Arizona transmission facilities. During my employment at the Commission, I have investigated numerous system disturbances on behalf of the Commission. A 1999 blackout of Southern Arizona, a 2001 blackout of Gila Bend, and several extra high voltage ("EHV") disturbances occurring in 2003 and 2004 are among the system disturbances I have investigated. My most recent investigations were of the Westwing and Deer Valley Substation fires.

I chaired a series of Commission Distributed Generation workshops in 1999 and have participated in the revision of Arizona's electric retail competition rules. I have also inspected physical electric utility plant consisting of generation, transmission and distribution facilities. Such facility inspections were necessary to make a "used and useful" determination for rate case applications and to ascertain the level of security, safety, operational integrity, and maintenance exhibited by such facilities.

Q. Please describe other pertinent work experience.

A. I have over 27 years of experience as an engineer and manager in the electric utility industry. I was employed by the Salt River Project from 1968 through 1995. During that time I: 1) analyzed and planned transmission and distribution system improvements; 2) managed the design and consultation services required for retail customer projects; and 3) served as primary contact for local municipalities regarding siting of facilities and utilizing funds for aesthetic treatment of water and power facilities. I also performed ancillary functions such as development and management of capital improvement budgets; formation and modification of system planning, operational and maintenance policies, procedures and practices; and creation, modification and administration of new contribution in aid of construction charges and tariffs.

Q. Have you previously testified before this Commission?

A. Yes. I have extensive experience testifying before the Commission. I have testified on numerous occasions regarding quality of service to electric customers in the City of Nogales and Santa Cruz County. I was a Staff witness regarding the 2003 competitive wholesale power solicitations required by the Commission. I have provided testimony for over 35 power plant and transmission line applications for a Certificate of Environmental Compatibility. My experience filing engineering reports and providing testimony for the

Commission in rates cases is most applicable to this case. I have provided engineering reports and rate case testimony for Duncan Valley Electric Cooperative, Navopache Electric Cooperative, and the Arizona Public Service Company ("APS") and an Open Access Transmission Tariff ("OATT") case for Southwest Transmission Cooperative ("SWTC").

PURPOSE AND PREPARATION OF TESTIMONY

Q. What is the purpose of your testimony in this case?

A. I am providing testimony concerning the security, safety, operational integrity, and maintenance status of APS's electric system. My testimony has a twofold purpose. It offers an assessment of the quality of service provided by APS to its customers. Secondly my testimony determines to what degree the test-year APS facilities are "used and useful."

Q. How have you prepared for your testimony?

A. I have reviewed information on file, issued data requests to APS, inspected APS's facilities and talked with APS personnel.

Q. When did you inspect APS's facilities?

A. I inspected APS's electric system during six consecutive days of site visits between July 24, 2006 and July 31, 2006. My observations are documented in the engineering report attached as Exhibit JS-1.

Q. What APS personnel have you talked with concerning this docket?

A. I have talked with Mr. Steve Bischoff, Mr. Stan Sierra, Mr. Pete Atwell, Mr. John Lucas, Mr. Dave Simonton, Ms. Jennie Vega, Ms. Angela Allison, and numerous field personnel during the course of my site visits to APS facilities.

Q. What documentation have you reviewed in preparing your testimony?

A. I have reviewed all rate application material filed by the applicant and numerous responses to Staff data requests. I also reviewed testimony and ACC engineering reports previously filed over the course of the last few years concerning other APS proceedings at the Commission. The ACC engineering report for this case is attached as Exhibit JS-1.

Q. Is your testimony herein based upon the aforementioned facility site observations, conclusions drawn from review of available documentation, information gathered by talking with applicant personnel and your educational background and work experience as a utility professional?

A. Yes it is.

FACILITIES CONSIDERED IN TESTIMONY

Q. Have you reviewed the APS application and testimony regarding facilities it proposes to include in rate base for this case?

A. Yes. I reviewed the respective rate schedules to ascertain what facilities I needed to make a used and useful determination for. This information was used to assist in my selection of facilities for a site visit.

Q. What other facilities are considered in your testimony?

A. I also visited other APS facilities to ascertain the on going status of maintenance, construction and repair practices contributing to the quality of service provided by APS. An outline of all APS facilities considered in my site visits is documented in Exhibit 2 of the ACC Engineering Report. A sampling of seven generating plants and 35 transmission and distribution substation facilities were visited.

JUSTIFICATION OF NEED FOR RECENT IMPROVEMENTS

Q. Briefly describe the fundamental justification of need for the many improvements being made by APS.

A. Major capital improvements were made to remedy and mitigate the causes and effects of the Westwing and Deer Valley Substation fires and to preclude a reoccurrence.

QUALITY OF SERVICE ASSESSMENT

Q. Please describe how you determined the quality of service being provided by APS to its customers.

A. Staff first considered trends in the APS reportable outage reports filed monthly with the Commission. Then actual APS distribution system reliability data was compared to the typical reliability indices for US utilities and APS system thresholds. Staff also considered the nature of customer complaints filed by APS consumers regarding quality of service. On this basis, Staff made an objective assessment of the quality of service being provided to APS distribution system customers. Finally, Staff coupled the above assessment with a physical inspection of a sampling of APS facilities.

Q. Have you determined if APS facilities are properly planned, designed, constructed, maintained and operated to achieve an appropriate level of reliable service to its customers?

A. Yes.

USED AND USEFUL DETERMINATION

Q. Please describe how you determined if the APS 2005 test year capital improvements were used and useful.

A. A used and useful determination requires a physical survey of new and improved facilities to assure completion of construction, validation that equipment is fully operational, and that the facilities meet National Electric Safety Code ("NESC") requirements per Arizona Administrative Code R14-2-208. Staff's used and useful determination of APS 2005 capital improvements was based upon inspection of a sampling of APS facilities and review and analysis of the company's response to data requests concerning its capital improvements. Choosing an appropriate sample of facilities to inspect was a fundamental requirement of Staff's used and useful determination. Staff's expertise was also critical in assembling criteria so a valid sample of facilities could be selected for field observation.

Q. Please summarize your observations of the site visits to APS facilities.

A. My observations and the results of my inspection of APS facilities are documented in my Engineering Report attached as Exhibit JS-1. In summary, my conclusions are:

- The scope of system improvements since the Westwing and Deer Valley Substation fires is substantial and impressive to observe in the field.
- Most of the electric transmission systems including substations were well maintained in terms of security in and around the substations, and of proper maintenance of equipment in the yard and in the switchgear rooms.
- Poor performing substations and distribution feeders are being maintained, refurbished and repaired in a logical and sound manner. Some of these improvements being made to the facilities serving tribal territories are effectively improving service.

- As recommended by APS Consultant EPRI Solutions, Inc., APS formed a Predictive Maintenance Team to focus on predictive and preventive maintenance activities to find and repair equipment prior to failure. Maintenance records looked at randomly during site inspections reflects the results of predictive maintenance.

Q. Have you determined if the capital improvements made by APS are "used and useful?"

A. Yes. All the electric facilities I observed during my six days of touring APS facilities were operational and well maintained. Therefore, I conclude the APS test year improvements are used and useful.

SUMMARY OF TESTIMONY CONCLUSIONS

Q. Please summarize the conclusions of your testimony.

A. Utility plant improvements constructed by APS in calendar year 2005 were appropriate and necessary to maintain reliable, efficient and cost effective service to its customers and the wholesale market. The justifications of need for such facilities were established before the Commission in prior proceedings. All utility plant contained in APS' rate application is "used and useful" in reliably delivering the energy needs of existing retail customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ENGINEERING REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

ARIZONA PUBLIC SERVICE COMPANY
RATE CASE
DOCKET NO. E-01345A-05-0816

STAFF'S QUALITY OF SERVICE ASSESSMENT
AND
USED AND USEFUL DETERMINATION

AUGUST 18, 2006

JDS:APSRateEngrRpt

STAFF ACKNOWLEDGMENT

This Engineering Report was prepared by the Arizona Corporation Commission Utilities Division ("Utilities Division") for use in the Arizona Public Service Company ("APS") rate case, Docket No. E-01345A-05-0816. It provides an analysis of the quality of service provided by APS for calendar years 2000 through 2005. It also provides a used and useful determination regarding capital improvements made in the rate case test year: 2005. The report documents an engineering assessment by Jerry Smith of the Utilities Division regarding these two matters.

Jerry Smith actively monitors quality of service matters for all Arizona utilities on an ongoing basis. His quality of service assessment of APS is based upon inspection of a sampling of APS facilities and review and analysis of the company's response to data requests concerning quality of service matters. Mr. Smith also documents the statistics of customer complaints filed with the Commission regarding quality of service matters.

A used and useful determination requires a physical survey of new and improved facilities to assure completion of construction, validation that equipment is fully operational, and that the facilities meet National Electric Safety Code ("NESC") requirements per Arizona Administrative Code R14-2-208. Mr. Smith has extensive industry experience regarding such investigations. His used and useful determination of APS 2005 capital improvements is based upon inspection of a sampling of APS facilities and review and analysis of the company's response to data requests concerning its capital improvements.

Jerry D. Smith
Electric Utility Engineer

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PURPOSE OF ENGINEERING REPORT

This engineering report serves a two fold purpose. It documents a quality of service assessment of Arizona Public Service Company ("APS") performed by Utilities Division Engineering Staff ("Engineering"). Secondly it provides a used and useful determination of APS capital improvements for test year 2005 also performed by Engineering. The report is filed with the Arizona Corporation Commission ("Commission") in support of the Commission Staff's ("Staff") evidentiary record for the APS rate case, Docket No. E-01345A-05-0816.

FRAMEWORK OF QUALITY OF SERVICE ASSESSMENT

Engineering's quality of service assessment of APS covers the calendar years 2000 through 2005. It is based upon data collected via data requests of APS and site visits of a sampling of the worst performing APS facilities. A 2004 Biennial Transmission Assessment ("BTA") was performed in accordance with Arizona Revised Statute §40-360.02.G. A 2006 BTA is currently in progress. Each BTA determines to what degree the existing and planned transmission system facilities in Arizona adequately meet the energy needs of the state in a reliable manner. This assessment also incorporates findings of the Commission's investigation of the Summer 2004 transmission outages in Docket No. E-00000J-04-0522.

In addition, Engineering monitors quality of service matters for utilities in the state of Arizona in accordance with Arizona Administrative Code R14-2-208 which describes the provision of service required of electric utilities. APS routinely files a monthly summary report for all outages resulting in 1000 customer hours of service interruption. This quality of service assessment considers findings of the APS report filed in accordance with Commission Decision No. 67744 regarding quality of service to Tribal Territories.[1] Consumers also may opt to file a complaint regarding quality of service with the Commission's Consumer Services Section. This quality of service assessment considers the performance of APS in each of the aforementioned categories.

However, the Commission has adopted a North American Reliability Council ("NERC") definition of reliability for Engineering's use in the Biennial Transmission Assessment. Reliability is comprised of two components: adequacy and security. Adequacy is the ability of an electric system to supply the aggregate electrical demand and energy requirements of its customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. On the other hand, security is the ability of an electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. These components of reliability are very subjective, are not easily measured and leave much to interpretation. Nevertheless, this document does highlight several major transmission disturbances that have resulted in interruption of service to APS customers since 2000.

[1] Reliability Review of Electric Service to Tribal Territories, Arizona Public Service Company, October 5, 2005.

Many utilities use numerical indices as a measure of an average customer's distribution service reliability. Such reliability indices are typically computed on an annual basis. A utility may then set reliability targets based upon benchmarked data from its own system. The Institute of Electrical and Electronic Engineers ("IEEE") has adopted a standard definition for several reliability indices for electric distribution systems and established a national benchmark database via a 1995 IEEE survey of the electric utility industry. The most commonly used reliability indices are System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), and Customer Average Interruption Duration Index ("CAIDI"). All three reliability indices are defined in IEEE Standard 13-2003, *IEEE Guide for Electric Power Distribution Reliability Indices*.

SAIFI is the average number of interruptions experienced by customers per year. SAIDI is the average number of interruption minutes experienced by customers per year. CAIDI is the average duration of interruptions. Per Rural Utilities Service ("RUS") Bulletin 161-5, the RUS considers a SAIDI of five hours (300 minutes) or more per consumer as unacceptable except under very unusual circumstances, such as a natural disaster. The IEEE 1995 Survey established typical reliability index values for the electric utilities in the United States as displayed in the following table.

Table 1
Typical Reliability Index Values for US Utilities

Average	SAIFI	SAIDI	CAIDI
Top quartile	0.90	54	55
Second quartile	1.10	90	76
Average	1.26	117	88
Third quartile	1.45	138	108
Bottom quartile	3.90	423	197

APS has been using a one-minute "Sustainable Outage" threshold when collecting outage data. This yields a more conservative result than the IEEE five-minute threshold. This seems to be a sound practice since outages of transmission lines operated at 69 kV or higher tend to be shorter than five minutes but longer than 1 minute. Otherwise outages of transmission lines that result in interruption of service could be excluded from the reliability assessment data.

The lognormal distribution is used for electric distribution system reliability data. As such the arithmetic mean and standard deviation are used to estimate confidence levels for the collected data. IEEE 1366-2003 utilizes 2 and ½ standard deviations ("2.5β") above the statistical mean for establishment of a reliability indices threshold. APS, on the other hand, utilizes one standard deviation above the statistical mean for its reliability indices threshold. APS then utilizes this more conservative reliability threshold for contrasting the attributes of rural and urban distribution feeders in the following categories: 1) single transmission source vs. redundant transmission source and 2) overhead vs. underground distribution construction. The following table and Exhibit 1 depict how 2005 outages modified the APS reliability threshold first reported in its prior *Reliability Review of Electric Service to Tribal Territories* Report.

Table 2
APS System Reliability Threshold

	2002-2004*			2002-2005**		
System Attribute	**SAIFI**	**SAIDI**	**CAIDI**	**SAIFI**	**SAIDI**	**CAIFI**
Single Transmission	6.77	567.10	175.40	7.68	477.40	156.40
Redundant Transmission	3.03	189.60	147.90	3.33	158.80	140.50
Overhead Distribution	6.40	572.10	126.20	7.25	486.40	176.90
Underground Distribution	2.40	128.60	190.00	2.48	103.40	121.90

NOTES:
* APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437, October 5, 2005.
** APS's response to Staff Data Request JDS 2-7, Docket No. E-01345A-05-0816

Engineering proposes to first consider trends in the APS reportable outage reports filed monthly with the Commission. Then actual APS distribution system reliability data will be compared to the typical reliability indices contained in Table 1 and Table 2. Engineering then proposes to consider the nature of customer complaints filed by APS consumers regarding quality of service. On this basis, Engineering can make an objective assessment of the quality of service being provided to APS distribution system customers. Coupled with a physical observation of a sampling of APS facilities, a determination can be made regarding the effectiveness of the various APS design, construction, maintenance, and repair practices.

FRAMEWORK OF USED AND USEFUL DETERMINATION

A used and useful determination requires a physical survey of new and improved facilities to assure completion of construction, validation that equipment is fully operational, and that the facilities meet National Electric Safety Code ("NESC") requirements per Arizona Administrative Code R14-2-208. This used and useful determination of APS 2005 capital improvements is based upon inspection of a sampling of APS facilities and review and analysis of the company's response to data requests concerning its capital improvements. Choosing an appropriate sample of facilities to inspect is a fundamental requirement in performing any valid used and useful determination. The investigator's level of industry experience is also critical in assembling criteria by which a valid sample of facilities is selected for field observation.

It was determined that a site visit of APS facilities was needed for both the quality of service assessment and the used and useful determination. However, APS has a large inventory of existing, new and upgraded facilities located state-wide. This made selection of a sample of facilities for field observation a necessity. APS' service area is segregated into five divisions: Metro, Northeast, Northwest, Southeast, and Southwest. Therefore, Engineering organized its field visits by APS Division and selected a reflective sample of generation, transmission and distribution facilities in each.

Exhibit 2 was compiled to facilitate a selection of APS facilities for a site visit. It lists the worst performing substation in each of the five APS Divisions for each year from 2003 through 2005. Similarly, it lists the three worst performing distribution feeders in each APS Division for each of the same years. It also lists the 2005 capital improvements constructed by APS in the form of new transmission lines (69 kV and above), distribution feeders, and new or upgraded substations. Finally, the Arizona power plants (except Palo Verde and Redhawk) owned and operated by APS and located in each APS Division are listed.

It was determined that by visiting all of the worst performing substations and about half of the new or upgraded substations listed in Exhibit 2 many of the worst performing distribution feeders would also be observed. Eastgate and Havasu were the only two worst performing substations not visited. The 2005 new and upgraded facilities selected for site visits were chosen primarily based upon improvements to correct previously poor performing sites or planned in response to scheduled maintenance discoveries. Capital improvements were afforded a higher visitation priority if they stemmed from implementation of recommendations filed with the Commission following the Summer 2004 outage events that lead to damaged equipment and a Westwing Substation fire. Redhawk and Palo Verde are the only APS solely or jointly owned and operated power plants in Arizona that were not included for visitation. Redhawk was inspected in 2002 by Electric Utilities Engineer, Prem Bahl, after it commenced commercial operation. An engineering report of that investigation was filed with the Commission. The Palo Verde Nuclear Generating Station was excluded because it has previously been visited and is part of an on going Commission investigation regarding unit outages that occurred in 2005.

During electric facility site visits Engineering generally ascertains: 1) facility security, 2) that proper safety and fire protection measures are employed, 3) all equipment have been constructed in compliance with NESC requirements, and 4) the operational status of facility. The site must be secure with proper height enclosures topped with either barbed wire or razor ribbon, and gate(s) and control house(s) are locked. Proper signage must be prominently displayed to inform the public that the facility poses an electric safety hazard. Existence of a formal employee safety training program and employee participation is established. Each site is observed to ascertain that it is a safe working environment. Employee adherence to safe operating practices is also observed in the field. Particular attention is given to fire extinction capability, proper separation of equipment or use of fire wall barriers, and existence of oil cache basins for transformers.

Confirmation that equipment exists in the field and is operational is a prerequisite for a used and useful determination. Therefore the operational readiness status of all onsite equipment is noted. Presence of a properly maintained substation DC battery supply is verified. Equipment maintenance needs are also observed and maintenance practices confirmed. Storage of damaged or non-useable equipment onsite is discouraged. However, onsite storage of equipment for future construction projects or staging of maintenance and repair activities at remote sites is an acceptable practice. Storage of a mobile or spare transformer at a remote substation is an example of this practice.

SITE VISITS AND FIELD OBSERVATIONS

Site visits were arranged and organized for each of the five APS Divisions. APS Northeast Division facilities were inspected on July 24, 2006. The Northwest Division was visited on July 25, the Southeast Division on July 26, and the Southwest Division on July 27. Two days, July 28 and July 31, were required to tour the Metro Division facilities. Jerry Smith was accompanied daily by two or three of the following APS personnel as he visited seven power plants and 35 substations over a period of six days. Power plant personnel were also interviewed at each of the power plants. The entourage visiting the Southeast Division and Southwest Division facilities was joined by local APS division personnel who graciously served as host.

Table 3
APS Personnel Accompanying Staff for Site Visits

	6/24	6/25	6/26	6/27	6/28	6/31
Jennie Vega		x		x	x	
Angela Allison	x		x			x
Pete Atwell	x	x				
John Lucas			x	x	x	x
Dave Simonton		x	x	x	x	

Engineering postulates that the substations and power plants sites visited and observations of transmission lines and distribution lines terminated at those same sites constitute a statistically valid sample of APS facilities. A complete set of photos taken during the site visits is provided as Appendix 1 on a compact disc ("CD"). Many of these photos depict security sensitive and critical infrastructure related information. Therefore the CD will be treated as confidential material in the filing of this report.

All sites visited were secure with enclosures of the proper height and were topped with either barbed wire or razor ribbon. Substations in rural settings were generally enclosed by chain link fences while those in urban settings were generally enclosed by masonry walls. All gate(s) and control house(s) were properly locked. Some facilities were protected by proximity alarms. The extra high voltage transmission substations and power plants utilize a security camera system to monitor the site. All but one power plant has personnel onsite 24 hours per day. A building is provided at the front gate of all but two power plants to house security personnel as needed. Proper signage was prominently displayed at each site to inform the public that the facility poses an electric safety hazard. A portfolio of photos depicting these observations is provided in Appendix 1. This collection of photos is labeled "Security Related."

The facilities visited included a spectrum of substations exhibiting a variety of traits. The substations varied in vintage from old to new and even included temporary installations pending selection of a permanent site. Substation designs ranged from wooden platform construction to high profile steel bus structures and low profile bus configurations. The primary voltage class of substations included 69 kV, 115 kV, 230 kV, 345 kV and 500 kV designs. There was a balanced

mixture of rural and urban substations. Some substations had circuit breakers, motorized switches and control houses containing Supervisory Control And Data Acquisition ("SCADA") equipment, remote telemetry units, relays and communication equipment. Others simply had manual switches and fuses and no control house. Some substations had primary and/or secondary capacitors, reactors or voltage regulators for voltage control while others did not. A portfolio of photos depicting these observations is provided in Appendix 1 and is labeled "Vintage and Type."

The following capital improvements represent a significant portion of the corrective action taken by APS following the Summer 2004 transmission outages and Westwing and Deer Valley transformer fires. Examples of these capital improvements were observed during Engineering's site visits of APS facilities. Two portfolios of photos of such improvements observed during site visits been assembled in Appendix 1. These portfolios of photos are labeled "Post WWG Fire" and "Fire Mitigation."

1. Replacement of Type U bushings on transformers,
2. Use of Serveron units on bulk system transformers to monitor gas forming within a transformer,
3. Replacement of fire damaged transformers at Westwing and Deer Valley,
4. Installation of fire walls between transformers lacking suitable separation per IEEE Standards,
5. Placement of transformer cache basins with retaining walls or curbs for transformer oil containment,
6. Elimination of single points of failure for protection and control systems via the addition of new electronic relays to replace antiquated electro-magnetic devices, and
7. Implementation of fire mitigation measures at various substation sites.

The Commission's investigation of the Summer 2004 transmission outages and Westwing and Deer Valley fires documented an APS commitment to implement the EPRISolutions, Inc. recommendations regarding 14 areas of maintenance and repair practices. As a consequence APS formed a Predictive Maintenance Team to focus on predictive and preventative maintenance activities to find and repair equipment prior to failure. Vibration and acoustic monitoring and corona scanning are now used routinely as maintenance diagnostic tools. Visual inspections, thermal scanning, and Dissolved Gas Analysis ("DGA") and complete oil analysis of transformers have been increased. A regimented electric testing of substation transformers with expanded use of Doble test equipment, Sweep Frequency Response Analysis ("SFRA") and Leakage Reactance has been adopted by APS.

APS has proactively resolved a significant number of equipment problems by using these diagnostic tools and practices. Most of these equipment improvements listed below were observed during site visits to APS facilities. A portfolio of photos is provided in Appendix 1 that documents some of the equipment improvements benefiting from these extensive predictive maintenance practices. The portfolio of photos is labeled "New Maint Practices."

1. A 230 kV transformer was replaced at Pinnacle Peak Substation and Coconino Substation due to a DGA determining that the transformers were deteriorating internally.
2. A 230 kV transformer was replaced at Deer Valley Substation due to acoustic, vibration, and DGA determining that the transformer was deteriorating internally.
3. A new Deer Valley Substation 230 kV transformer was returned to the manufacturer due to a SFRA determining it was damaged during shipping from the manufacturer.
4. A 230 kV transformer at Cactus Substation was repaired following acoustic monitoring that discovered a nitrogen leak through the Current Transformer ("CT").
5. A 345 kV station post insulator was replaced at Preacher Canyon due to significant corona being detected by a corona camera.
6. A circuit breaker was replaced at Ocotillo due to a SF6 camera detecting a SF6 leak.
7. A 69 kV transformer was replaced at Jackson Street Substation due to internal damage detected by vibration analysis and SFRA.

All newly constructed and improved facilities observed during the site visits were found to be in compliance with NESC requirements. Sites that were visited that had capital improvements reported by APS for 2005 test year purposes were found to actually have been constructed and were operational. A sufficient sample of 2005 improvements were observed in the field and suggests a "used and useful" determination for 2005 test year capital improvements is warranted. However, several items were observed that merit some attention. The list provided below is viewed by Engineering as minor issues offering opportunities for improvement. These items are likely already on the utility's to do list. Failure to take corrective action in the near term could elevate Engineering's concern if quality of service from these facilities begins to deteriorate. A portfolio of photos of these items is provided in Appendix 1 with the label "Areas for improvement."

- Chino Wells Substation is an old substation with old equipment serving water pumps for Chino Wells. The station service transformers are not in service and have been abandoned in place. The substation transformers are old and showed signs of old oil leaks and have older Type U bushings. The substation is scheduled for replacement or refurbishment in the next few years.

- The Fairview generator and an emergency 69 kV tie at Sulphur Springs Valley Electric Cooperative's ("SSVEC") McNeal Substation are of inadequate capacity to restore full service to all of the Southeast Division for an outage of the APS Adams to Mural 115 kV line. This service area has the potential of exhibiting quality of service concerns comparable to that of Nogales and Santa Cruz County. In fact, the Southeast Division is APS' poorest service performance division over the last five years. A second 69 kV tie is being sought with SSVEC.

- A new transformer was constructed at Humbug in 2005 without an oil cache basin. The second unit already has asphalt curbing to assure containment of transformer oil spills. It is assumed that the construction activity may not have been completed or the

cache basin may have simply been an oversight given the new focus of fire mitigation.

- Laguna Feeder #1 was rebuilt in 2005 as an underbuild on a 69 kV line on steel poles. The telephone lines previously in joint use on the old wood pole still remain in service with the poles topped above the telephone line. The wood poles are leaning in such a manner as to likely pose a public safety concern for road crossings. This is not an APS problem but is reflective of untimely relocation of joint use facilities on poles that are being removed and replaced.

- One 69 kV steel pole just north of Laguna Substation was observed to have experienced a hit and run vehicular accident. The base of the steel pole was severely crushed. The pole appears to be structurally sound but obviously needs replacement.

- Paulden Substation had a larger auger bit stored in an inappropriate location. It was placed in a position that could pose an obstacle for a vehicle's ingress to the site if occurring at night. Simply placing the auger bit adjacent to the substation fence would resolve this safety concern.

- The San Luis Substation control house has had a roof leak. A black garbage bag was suspended above electronic equipment on the top of a control rack to protect the equipment until the leak was resolved. The roof leak needs to be repaired and the plastic garbage bag removed to enable proper equipment ventilation void of moisture and to avoid the bag becoming a loose impediment in the control house.

TRANSMISSION ASSESSMENT

Engineering conducted the Commission's third biennial transmission assessment in 2004. Engineering investigated the ability of Arizona's transmission system to adequately deliver energy to the state's retail consumer markets as well as import energy from or export energy to the regional transmission grid with which it is interconnected. Adequacy of existing Arizona transmission lines and planned additions between 2004 and 2013 was determined and documented in a Staff report adopted by the Commission via Decision No. 67457.[2] The 2006 BTA is currently in progress but has not reached a point where findings of fact are available for inclusion in this analysis.

Engineering concluded in its third BTA that the electric industry in the State of Arizona had been very responsive to concerns raised in the Commission's first and second BTA. It further concluded that in general the existing and planned Arizona transmission system meets the load serving requirements of the state in a reliable manner. APS is a major transmission provider in the state of Arizona and therefore the conclusions derived from the Biennial Transmission Assessment are largely a reflection of the quality of transmission service provided by APS.

[2] Third Biennial Transmission Assessment 2004-2013, Docket No. E-00000D-03-0047, November 30, 2004.

However, the third BTA report continued to raise concerns about the adequacy of the state's transmission system to reliably support the competitive wholesale market emerging in Arizona. The third BTA conclusions were based upon the following findings:

- Very little long-term firm regional transmission capacity is available to export or import energy over Arizona's transmission system.
- There are transmission import constraints for five geographical load zones in Arizona: Phoenix metropolitan area, Tucson, Yuma, Santa Cruz County and Mohave County. Planned transmission enhancements will help mitigate such constraints in all but Mohave County.
- Transmission from Palo Verde to California is inadequate to allow all Palo Verde Hub generation full access to the California market under weak Arizona market conditions.
- Some new power plants have interconnected to Arizona's bulk transmission system via a single transmission line or tie rather than continuing Arizona's best engineering practice of multiple lines emanating from power plants.

During the period of this quality of service assessment, APS experienced four transmission outages that resulted in interruption of service to distribution customers. On July 1, 2003 the failure of a 230 kV circuit breaker at Pinnacle Peak substation resulted in APS and the Salt River Project ("SRP") interrupting service to 46,673 customers in the Phoenix metropolitan area to prevent cascading of the disturbance to other systems. Similarly on July 28, 2003, APS operating personnel took steps to shed local load by interrupting service to 119,348 customers in response to a 500 kV switching incident at the Hassayampa Switchyard that resulted in tripping of approximately 2600 MW of generation. On June 14, 2004 the Liberty to Westwing 230 kV line experienced a failure due to a fault not being cleared in a timely fashion. This event led to damage of transformers at Westwing which eventually caught fire on July 4, 2004. On July 20, 2004 failure of transformer bushings at Deer Valley Substation resulted in another transformer fire and led to interruption of service of 95,373 customers.

In each instance APS notified and informed the Commission of its action and how it was managing restoration of service to customers. The effect of these transmission events on APS' distribution reliability performance indices is discussed later in this report. APS management of and operational response to the Summer 2004 transmission outage events was the focus of an extensive Commission investigation.

DISTRIBUTION SYSTEM RELIABILITY INDICES

Engineering has reviewed data supplied by APS regarding its distribution system reliability indices for the years 2000 through 2005. APS provided outage statistics concerning Commission reportable outage events per Engineering's request. APS also provided SAIFI, SAIDI, and CAIDI data under a confidentiality agreement for its entire distribution system and for its five geographical regions: Metro, Northeast, Northwest, Southeast, and Southwest. This information is displayed respectively in tabular and graphical form in Exhibits 3 and 4. A summary of the reliability indices for the three worst performing feeders in each APS Division

for 2003 through 2005 have been assembled as Exhibit 5. Exhibit 6 updates the summary of reliability indices for every APS feeder providing service to tribal territories from that previously filed with Commission. Exhibits 5 and 6 contain detailed information regarding specific substations and feeders and are therefore confidential. They have been filed as part of the confidential material in Appendix 1. All four of these exhibits form the basis for Engineering's summary analysis of APS distribution system reliability performance provided below.

The APS distribution system reliability indices are determined in large part by the performance of its Metro Division. The Metro Division is largely comprised of the Phoenix metropolitan area and is an urban service area representing approximately three quarters of the APS load. The Metro Division SAIFI, SAIDI and CAIDI reliability indices are the best of the five APS divisions for each of the last five years. The remaining four divisions are largely rural or small communities with limited distribution services whose operational character is more typical of rural distribution service. It is normal to expect such rural services to experience a greater number of service interruptions of longer duration due to: 1) longer length distribution feeders with aging distribution equipment due to slower growth patterns, 2) limited feeder switching capability among distribution substations, 3) remoteness of limited service personnel, and 4) geographic areas in which storm disturbances are more prominent.

The year 2005 was statistically not a good year for APS regarding sustained service interruptions to customers. The Commission requires that APS report outages resulting in 1,000 customer hours of service interruption. Exhibit 3 shows that the customer hours of interruption in 2005 was roughly three times that experienced in 2004. APS reports this 2005 increase is largely attributable to more extensive damage due to storm activity. Some of the outages occurred at times when the system was already in a state of reconfiguration for construction and maintenance activities. Customers served by APS Northwest Division facilities have been somewhat immune to the increased hours of outage over the last three years. The 2005 increase in reportable distribution outages predominantly affected Metro Division customers. On the other hand, the Southeast Division accounts for the majority of the 2005 increase in transmission reportable outages.

This phenomenon is partially explained by the reliability threshold statistics reported by APS in Exhibit 1. Customers served by overhead distribution feeders from a substation that has a single transmission line have about twice the number of outages and an outage duration of two to three times that of customers served by underground feeders from substations with redundant transmission lines. However, the customer average interruption duration remains comparable between the two groups of customers. This is the typical comparison of rural versus urban service. What is more significant in the Exhibit 1 data is that the reliability threshold in 2005 was reduced or improved over that reported for 2004. This implies that an improvement in the overall APS system reliability was achieved in spite of a 2005 increase in the incidence and duration of outages.

The actual APS reliability indices in Exhibit 4 have been compared to the IEEE typical industry indices listed in Table 1. Several conclusions can be drawn from this comparison. Over

the last four years the number of interruptions of service per customer per year for the entire APS distribution system listed on page 4-1 of Exhibit 4 has correlated to the second quartile of U.S. utilities in Table 1. The average number of hours of interruption per year for the entire APS distribution system listed on page 4-2 of Exhibit 4 falls within the second quartile of U.S. utilities in Table 1 except in 2005 it drops to just below average. The CAIDI reliability indices for the entire APS system listed on page 4-3 of Exhibit 4 is in the second quartile of utilities except for the year 2002 when it is in the third quartile of U.S. utilities. These statistics imply that APS is managing its entire distribution system on a comparable par with the better utilities in the nation.

Exhibit 4 documents that the APS division exhibiting the weakest reliability indices is the Southeast Division. However, at no time have the Southeast Division reliability indices exceeded the reliability threshold levels depicted in Table 1. This portion of the APS system provides service to the communities of Douglas and Bisbee. Engineering is aware of an extreme transmission outage that caused a major blackout of much of Southern Arizona in 2001. That transmission outage accounts for the less reliable service to Southeast Division APS' customers in 2001. Engineering was first alerted to concerns regarding potential quality of service for the APS Southeast Division when it was investigating service complaints for Santa Cruz County in 1999. In 2000 the utilities serving Southeastern Arizona performed a regional study and presented results to the Commission. It concluded that restorative service to APS' Southeast Division following a 115 kV line outage was best accomplished with remote operational control of the APS Fairview generation and remote controlled equipment that enabled closing of two 69 kV ties with Sulphur Springs Valley Electric Cooperative substations and the addition of 69 kV capacitors for voltage control. Engineering believes it prudent for the Commission to continue to closely monitor quality of service in the APS Southeast Division given its system topology and quality of service history.

Only four feeders had a CAIDI performance level exceeding the 2005 reliability threshold in Table 1 from 2003 through 2005. Exhibit 5 documents that corrective system improvements have been made to resolve performance woes of each of the four feeders. The four feeders in question are Preacher Canyon #6, Pollack #2, Rainbow Valley #1 and Vicksburg #4. Similarly, Exhibit 6 reveals that over the time period of 2002 through 2005 only six feeders serving tribal territories had an <u>average</u> CAIDI exceeding the Table 1 reliability threshold. Only two of those feeders exceeded the threshold level in 2005: Caywood #1 and Valley Farms#6.

QUALITY OF SERVICE COMPLAINTS

The Commission provides the opportunity for consumers to file complaints regarding the quality of service received from utilities under its regulatory jurisdiction. Table 2 summarizes the nature of quality of electric service complaints filed with the Consumer Service Section regarding service from APS for calendar years 2000 through 2005.

Table 4 statistics indicate that quality of service complaints are predominantly related to outages or interruption of service. The largest number of outage complaints occurred in 2000. However, the largest percentage of complaints regarding outages occurred in 2005. That was a

year in which the reliability indices previously discussed also reflected that APS customers experienced the largest number of average hours of outage per incident. APS experienced two major outages to its distribution system in the year 2001. Even so, its quality of distribution service overall was comparable to the better performing utilities in the nation.

The statistics provided by Table 4 also reveal the relationship of quality of service complaints to the total number of consumer complaints received from APS customers. The percent of total complaints about APS that are of a quality of service nature ranges between 5 and 12 percent. Engineering believes coupling these statistics with Consumer Services' experience in working with APS to resolve all complaints serves as an indication that the quality of customer service provided by APS is excellent.

Table 4
Quality of Service Compliant Summary[1]

Complaint Code	2000	2001	2002	2003	2004	2005
Defective equipment	3	0	0	0	2	4
Not working	5	3	3	0	1	3
Outage / interruption	37	30	11	17	23	65
Voltage	1	0	1	0	3	1
Engineering	0	0	0	0	0	1
Subtotal	46	33	15	17	29	74
Total Complaints	649	314	257	198	442	595
% Total Complaints	7.1 %	10.5 %	5.8 %	8.5 %	6.6 %	12.4 %

[1] Per Arizona Corporation Commission Consumer Service database.

STAFF CONCLUSIONS AND RECOMMENDATION

Engineering concluded in its second Biennial Transmission Assessment that in general the existing and planned Arizona transmission system meets the load serving requirements of the state in a reliable manner. APS is a major transmission provider in the state of Arizona. Therefore the conclusions derived from the Biennial Transmission Assessment are largely a reflection of the quality of transmission service provided by APS.

During the period of this quality of service assessment, APS experienced several transmission outages that resulted in interruption of service to distribution customers. In each instance APS notified and informed the Commission of its action and how it was managing restoration of service to customers. The scope of system improvements since the Westwing and Deer Valley Substation fires is vast and impressive to observe in the field. Major capital improvements have been made to remedy and mitigate the causes and effects of these events and to preclude a reoccurrence. Damaged equipment has been replaced and Type U transformer bushings are being replaced through out the APS system. Single points of failure for protection and control systems have been eliminated, fire mitigation measures have been implemented at

various substations, and fire wall and oil cache basins are being established at appropriate substations.

The Summer 2004 transmission outages and Westwing and Deer Valley fires also have yielded positive effects for Arizona consumers. APS has implemented EPRISolutions, Inc. recommendations regarding 14 areas of maintenance and repair practices. As a consequence APS formed a Predictive Maintenance Team to focus on predictive and preventative maintenance activities to find and repair equipment prior to failure. APS has proactively resolved a significant number of equipment problems by using these diagnostic tools and intensifying its maintenance practices. Improved service to future generations of customers is more likely to occur as a result of these efforts.

All newly constructed and improved facilities observed during Engineering's site visits were found to be in compliance with NESC requirements. Sites that were visited that had capital improvements reported by APS for 2005 test year purposes were found to actually have been constructed and were operational. A sufficient sample of 2005 improvements were observed in the field and suggests a "used and useful" determination for 2005 test year capital improvements is warranted.

Poor performing substations and distribution feeders are being maintained, refurbished and repaired in a logical and sound manner. Only four feeders had a CAIDI performance level exceeding the 2005 APS reliability threshold from 2003 through 2005. Corrective system improvements have been made to resolve performance woes of each of the four feeders. Four feeders serving tribal territories exhibited an average CAIDI exceeding the reliability threshold level for 2002 to 2005. However, only two of those feeders actually exceeded the threshold in 2005. This signifies that improvements being made to facilities serving tribal territories are effectively improving service.

The system reliability indices for the APS distribution system for 2000 through 2005 imply that APS is managing its entire distribution system on a par with the better utilities in the nation. The APS division exhibiting the weakest reliability indices is the Southeast Division. This portion of the APS system provides service to the communities of Douglas and Bisbee. In no instance did the Southeast Division reliability indices exceed the APS reliability threshold.

Between 5 and 12 percent of annual complaints about APS are of a quality of service nature. Quality of electric service complaints filed with the Consumer Service Section regarding APS service for the years 2000 through 2005 are predominantly related to outages or interruption of service. APS experienced numerous major outages during the period of this quality of service investigation. Even so, APS quality of electric service overall was comparable to the better performing utilities in the nation. Given Consumer Services excellent experience with APS in resolving complaints, Engineering finds the quality of customer service provided by APS to be excellent.

Engineering finds no reason to recommend consideration of quality of service mitigation measures as part of the pending APS rate case. However, Engineering does recommend that the Commission continue to monitor APS' quality of service as an integral part of required Biennial Transmission Assessments, through the Commission's existing outage reporting requirements, and via ongoing resolution of consumer complaints about APS service. Engineering further suggests that the Commission be particularly mindful of quality of service differences between the APS Metro Division and more rural service oriented APS divisions. It is for this reason that quality of service to the APS Southeast Division merits special scrutiny to assure service does not deteriorate and become problematic.

APS System Reliability Threshold

	2002-2004*			2002-2005**		
System Attribute	**SAIFI**	**SAIDI**	**CAIDI**	**SAIFI**	**SAIDI**	**CAIFI**
Single Transmission	6.77	567.10	175.40	7.68	477.40	156.40
Redundant Transmission	3.03	189.60	147.90	3.33	158.80	140.50
Overhead Distribution	6.40	572.10	126.20	7.25	486.40	176.90
Underground Distribution	2.40	128.60	190.00	2.48	103.40	121.90

NOTES:

* APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437,October 5, 2005

** APS response to Staff Data Request JDS 2-7, Docket No. E-01345A-05-0816

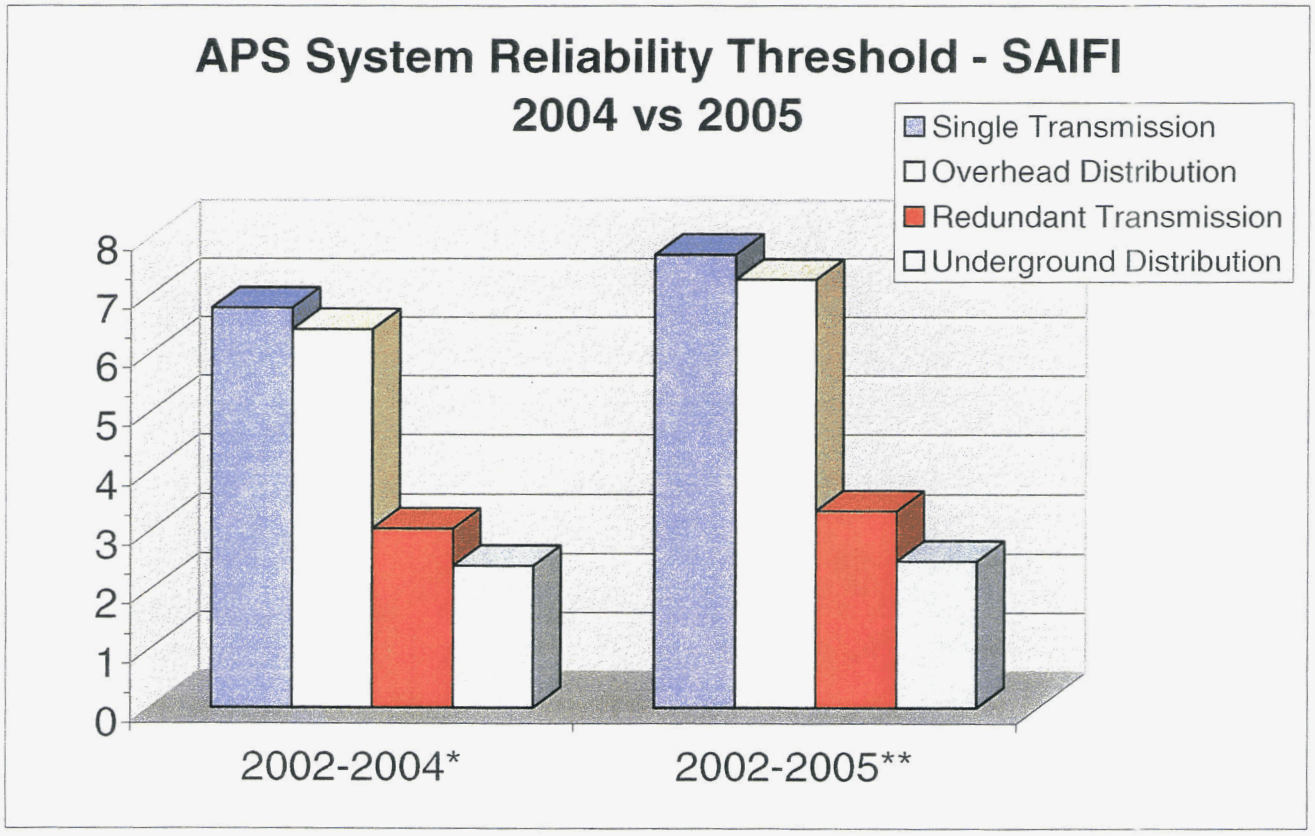
APS System Reliability Threshold - SAIFI

System Attribute	2002-2004*	2002-2005**
Single Transmission	6.77	7.68
Redundant Transmission	3.03	3.33
Overhead Distribution	6.40	7.25
Underground Distribution	2.40	2.48

NOTES:

* APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437,October 5, 2005.

** APS response to Staff Data Request JDS 2-7, Docket No. E-01345A-05-0816



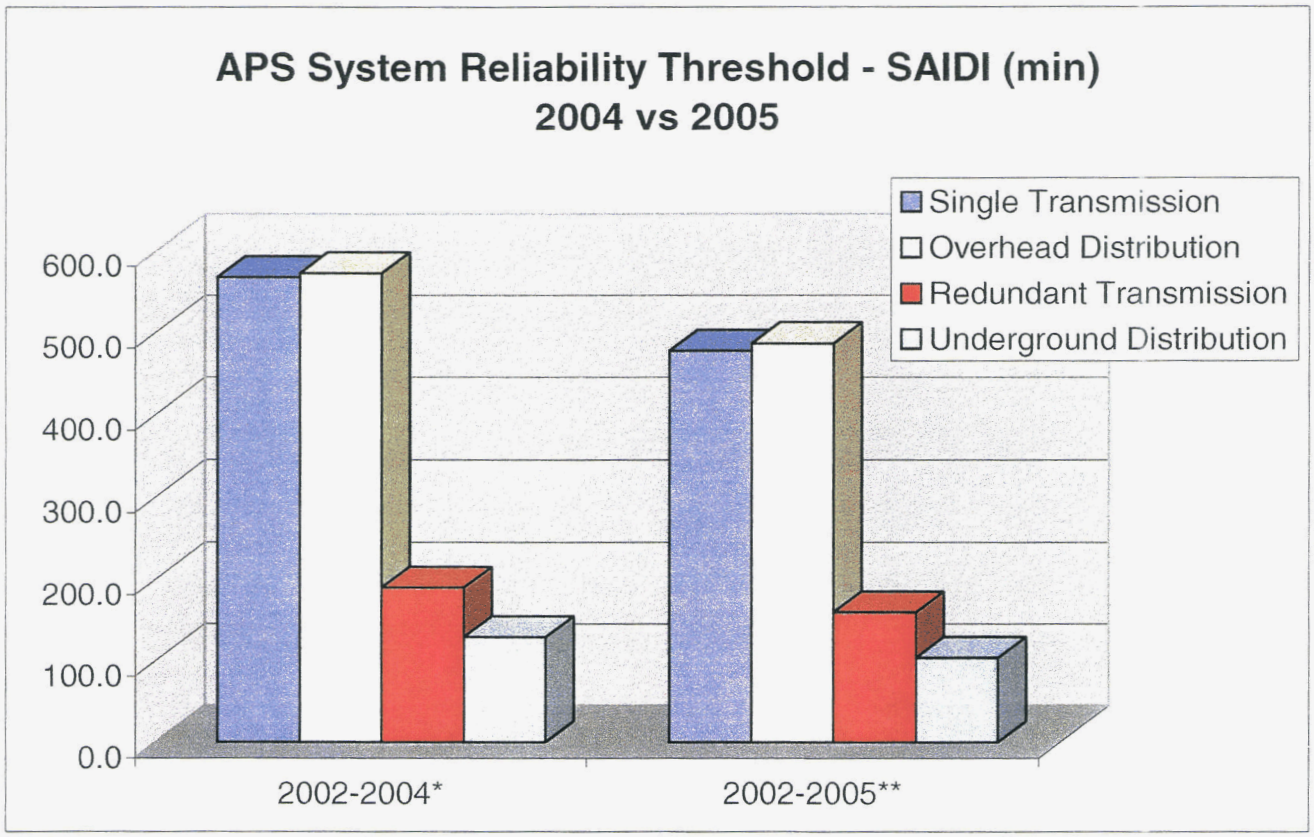
APS System Reliability Threshold - SAIDI (min)

System Attribute	2002-2004*	2002-2005**
Single Transmission	567.1	477.4
Redundant Transmission	189.6	158.8
Overhead Distribution	572.1	486.4
Underground Distribution	128.6	103.4

NOTES:

* APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437,October 5, 2005.

** APS response to Staff Data Request JDS 2-7, Docket No. E-01345A-05-0816



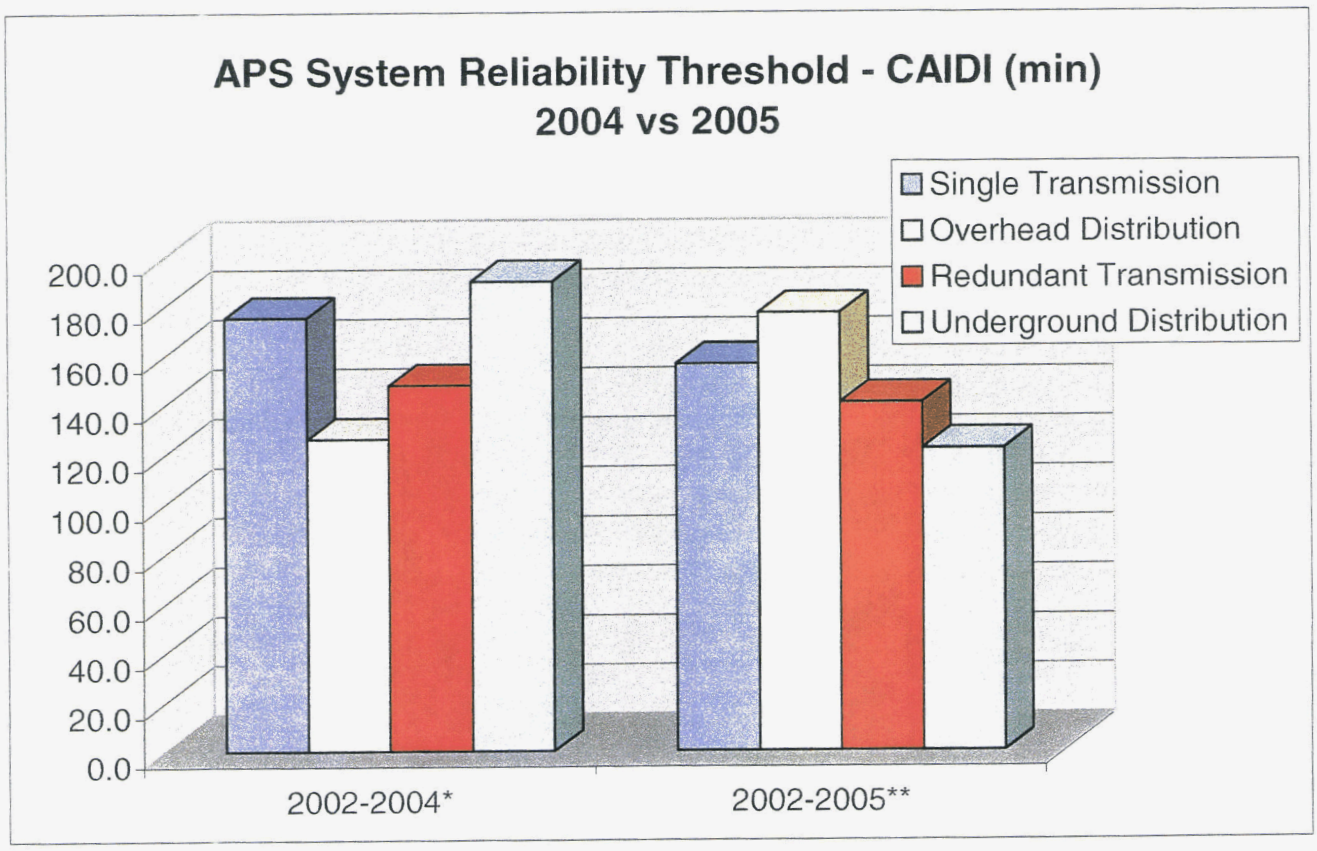
APS System Reliability Threshold - CAIDI (min)

System Attribute	2002-2004*	2002-2005**
Single Transmission	175.4	156.4
Redundant Transmission	147.9	140.5
Overhead Distribution	126.2	176.9
Underground Distribution	190.0	121.9

NOTES:

* APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437,October 5, 2005.

** APS response to Staff Data Request JDS 2-7, Docket No. E-01345A-05-0816



Key APS Metro Division Facilties*

	Worst Performing		2005 Capital Improvements		
Year	Distribution Sub	Dist. Feeder	Dist. Feeder	New/Upgrade Subs	New Trans
2003	Desert Springs	Metro #4 Downing #2 Humbug #10			
2004	Deer Valley	Encanto #13 23rd Street #20 Sherman St #22			
2005	Humbug	HappyValleyTemp#4 Indian Bend #10 Sherman St # 13	Dysart #17 Encanto #9 Filmore #19 Lincoln W. #3 McDowell #9 Meadowbrk #1 Meadowbrk #21 New River #2 Shaw #15 Sherman #14 Sherman #17 Sherman #22 23rd Street #18	Gavilan Peak 230/69 Stout, Polk, Oblerlin 69/12 Pyramid Pk 69/12 WWG 69/12 DeerVly 230/69-upgrade PPK 345/230 kV upgrade Garfield, Shea 69/12upgrade Rock Spr 69/12 -upgrade Greenbrier 69/12 upgrade Lincoln W. 69/12 Paradise 69/12 Colter, Dysart 69/12 Surprise, Waddell 69/12 Humbug 69/12	Gavilan Pk-Dove Valley 69 Adobe-Stout 69

APS Generation within Division Boundry:		
	Ocotillo W. Phoenix	

*Facilties visited highlighted in red

Key APS Northeast Dvision Facilites

	Worst Performing		2005 Capital Improvements		
Year	Distribution Sub	Dist. Feeder	Dist. Feeder	New/Upgrade Subs	New Trans
2003	Winslow	Preacher Canyon #6 Shumway #6 Shumway #2			
2004	Sandvig	Tusayan #14 Winona #1 Grand Canyon #1			
2005	Elden	Le Barron Hill #1 White Horse #1 Leupp Junction #1	Keems Cnyn #3 Keems Cnyn #5 Winslow #14 Woodruff #2	Matazal	Matazal -Tonto 69 Cholla-Keems Cnyn Flt Loc Blk Mesa-Tuba City Flt Loc Blk Mesa-Sandvig Flt Loc

APS Generation within Division Boundry:	Cholla	

*Facilties visited highlighted in red

Key APS Northwest Division Facilties*

	Worst Performing		2005 Capital Improvements		
Year	Distribution Sub	Dist. Feeder	Dist. Feeder	New/Upgrade Subs	New Trans
2003	Dewey	Delano #1 Weston Wells #3 Delano #5			
2004	Dewey	Sturm Ruger #10 Bagdad Townsite #10 Pollock #2			
2005	Morristown	Pres.-ChinoWells#4 Aguila #1 Paulden #2	Delano #5 White Spar #12	Aguila 69/12 - upgrade Cottonwood 69/12-upgrade Poplar Wash 69/12	

APS Generation within Division Boundry:		

*Facilties visited highlighted in red

jds:KeyFacilitySummary.xls

EXHIBIT 2

Key APS Souheast Division Facilties*

Year	Worst Performing		2005 Capital Improvements		
	Distribution Sub	Dist. Feeder	Dist. Feeder	New/Upgrade Subs	New Trans
2003	Eastgate	San Pedro #14 Rainbow Valley #1 Toltec #4			
2004	Toltec	Aztec # 10 Coolidge #2 Coolidge #1			
2005	Boothill	Rainbow Valley #5 Why #1 Perryville #1	Coolidge #2 Don Luis #3	Boothill 115/21 kV- upgrade Buckeye - upgrade Pinal 115/69/21kV Hayes Gulch 69/21 kV	Pinal - Hayes Gulch 69 kV

APS Generation within Division Boundry:	
Saguaro Sundance Fairview	

*Facilties visited highlighted in red

Key APS Southwest Division Facilities*

Year	Worst Performing		2005 Capital Improvements		
	Distribution Sub	Dist. Feeder	Dist. Feeder	New/Upgrade Subs	New Trans
2003	Havasu	Quechan #26 Gila (DOE) #2 Quartzsite #2			
2004	32nd Street	YumaPalmsTemp#2 Laguna #1 Gila (DOE) #2			
2005	San Luis	Vicksburg #4 Utting #1 Planet #1	Quartzsite #6	Marine Air 69/12 - upgrade N. Gila 500/69	

APS Generation within Division Boundry:

Yucca	

*Facilties visited highlighted in red

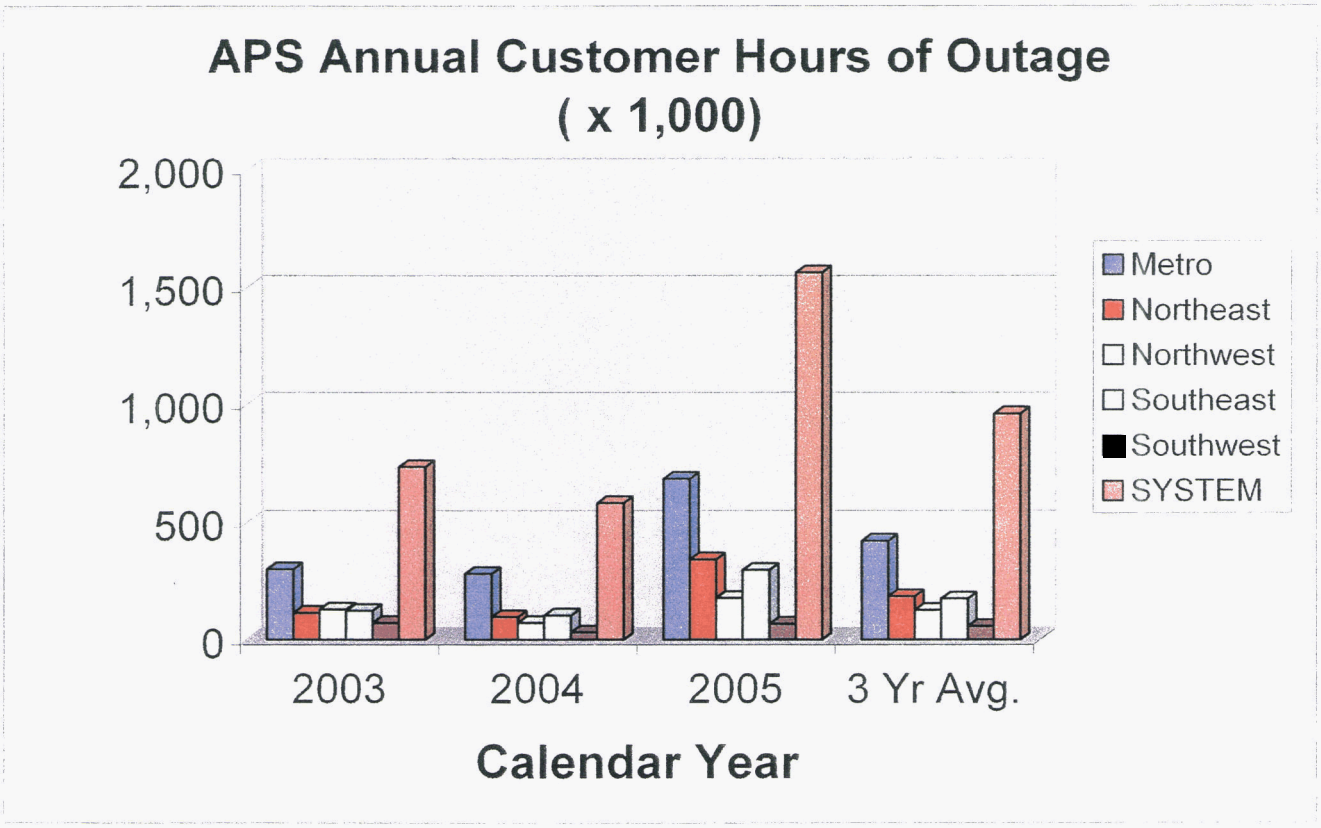
jds:KeyFacilitySummary.xls

EXHIBIT 2

Annual Customer Hours of Outage by APS Division*
(x 1,000)

	2003	2004	2005	3 Yr Avg.
Metro	299	280	684	421
Northeast	114	96	341	184
Northwest	128	71	177	125
Southeast	123	103	296	174
Southwest	71	31	67	56
SYSTEM	734	580	1,564	959

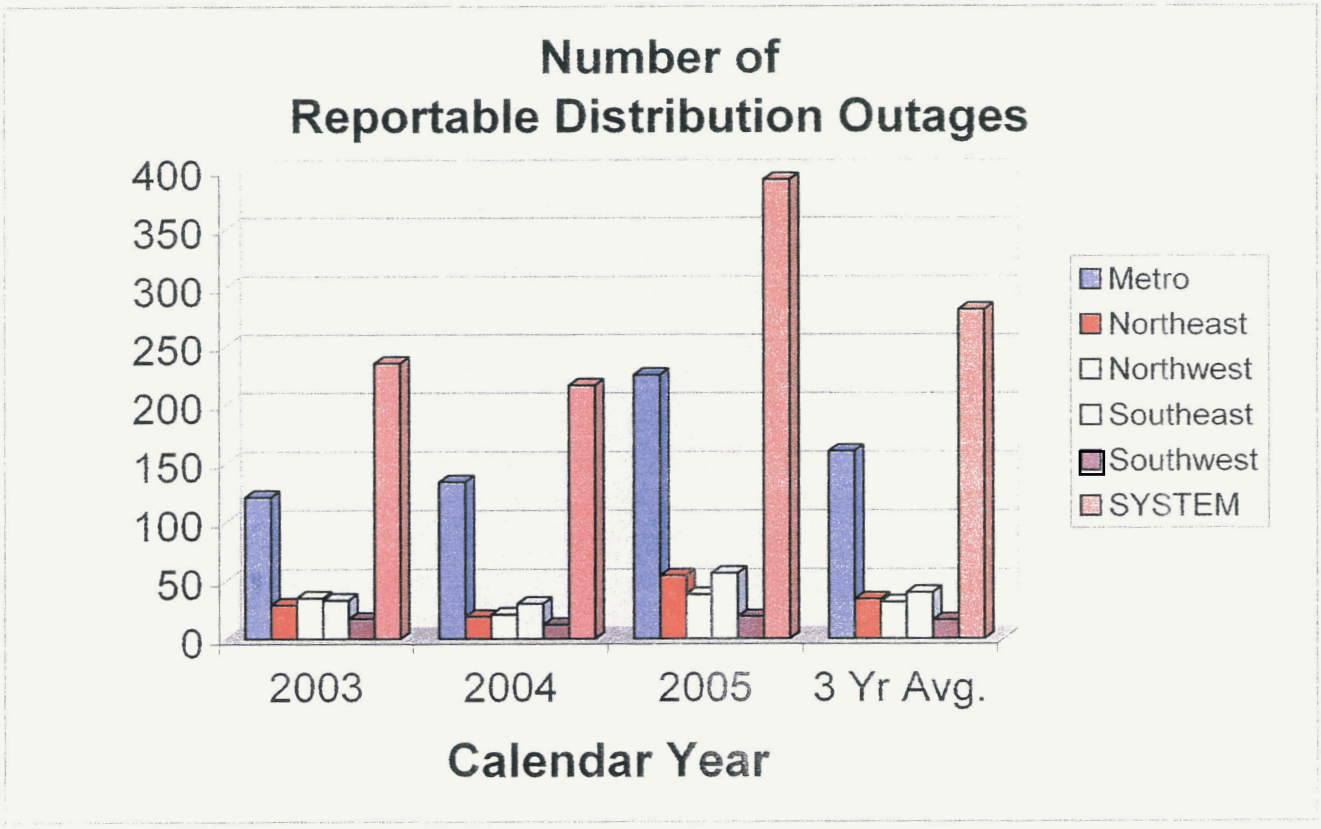
* per APS response to Staff Data Request JDS 2-1, Docket No. E-01345A-05-0816



Number of Reportable Distribution Related Outages by APS Division*
(ACC Reportable Outages = 1,000 Customer Hours or More)

	2003	2004	2005	3 Yr Avg.
Metro	121	134	225	160
Northeast	29	19	54	34
Northwest	35	21	38	31
Southeast	33	30	56	40
Southwest	17	12	19	16
SYSTEM	235	216	392	281

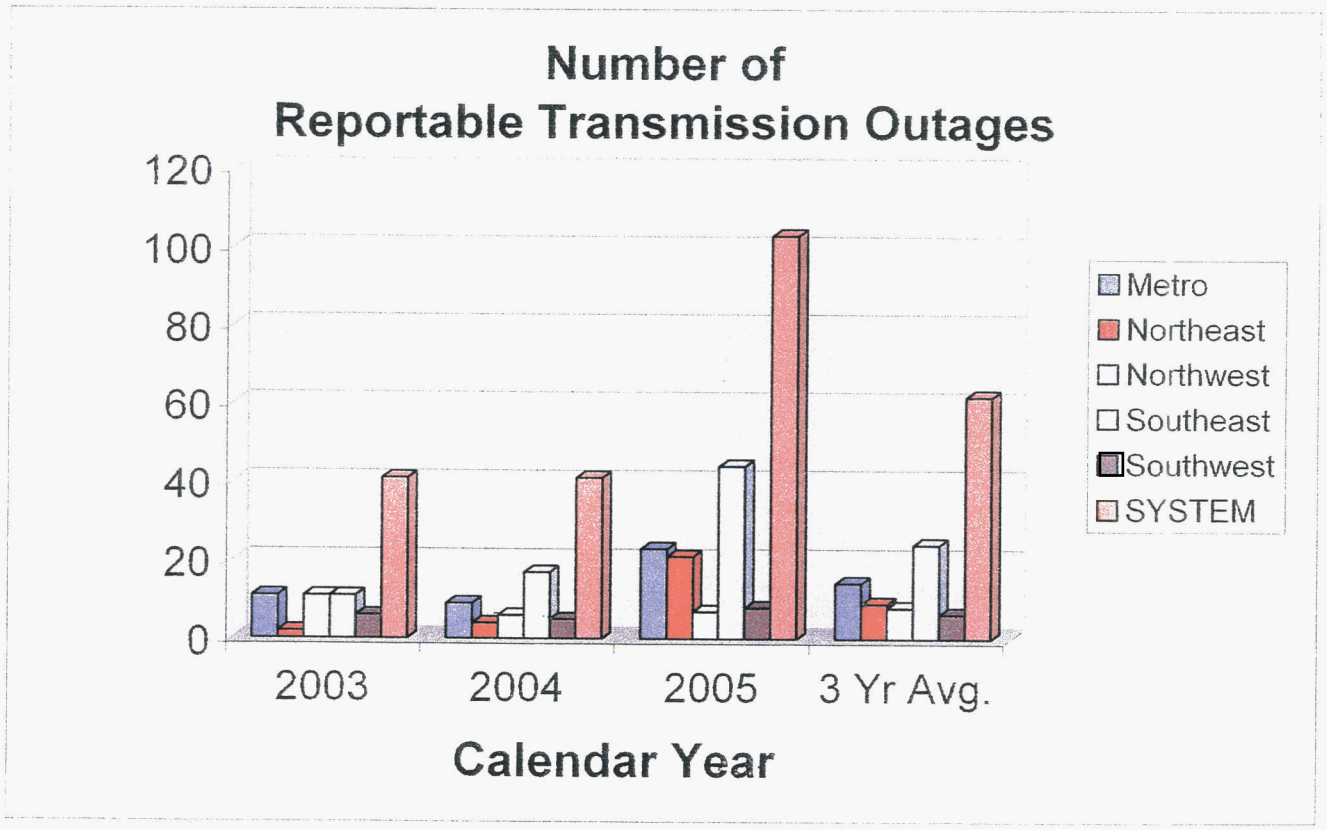
* per APS response to Staff Data Request JDS 2-1, Docket No. E-01345A-05-0816



Number of Reportable Transmission Related Outages by APS Division*
(ACC Reportable Outage = 1,000 Customer Hours or More

	2003	2004	2005	3 Yr Avg.
Metro	11	9	23	14
Northeast	2	4	21	9
Northwest	11	6	7	8
Southeast	11	17	44	24
Southwest	6	5	8	6
SYSTEM	41	41	103	62

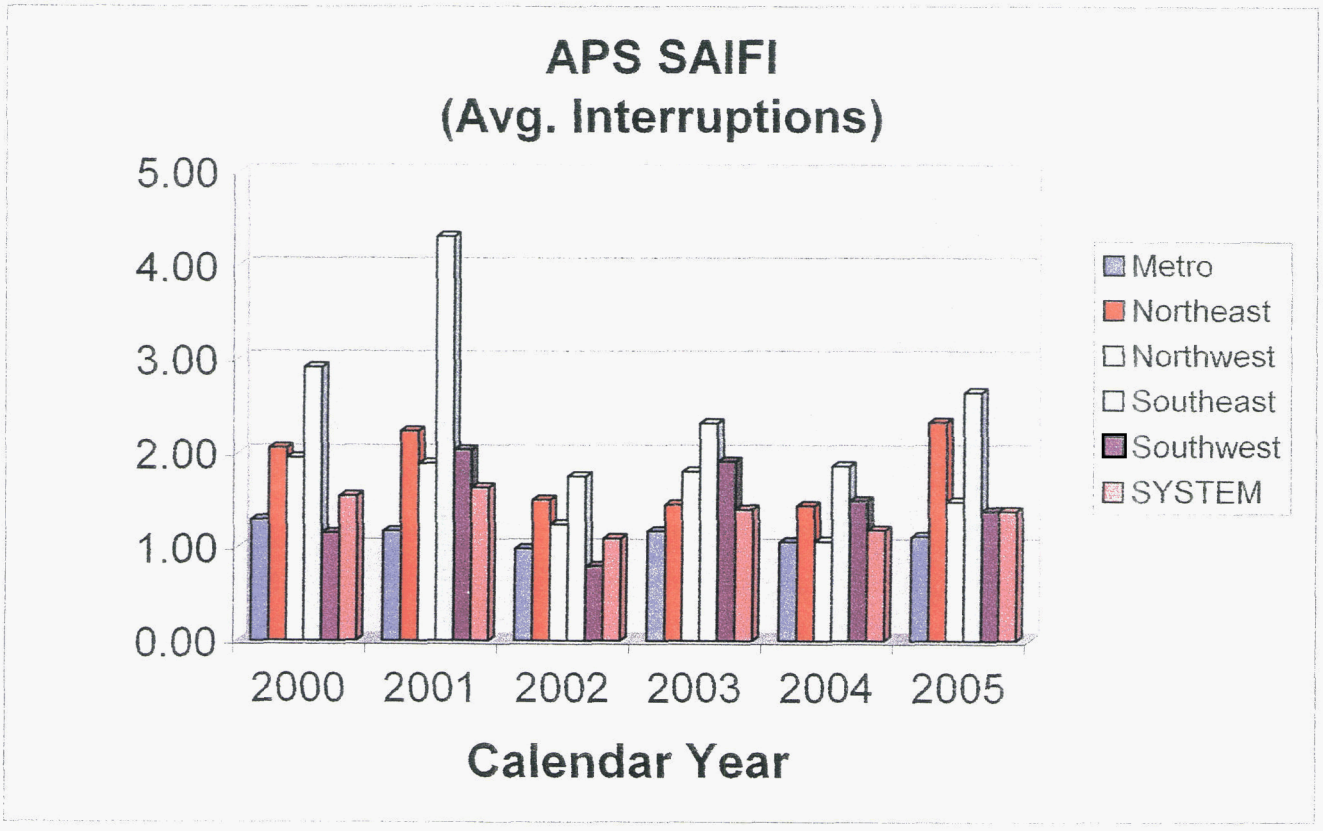
* per APS response to Staff Data Request JDS 2-1, Docket No. E-01345A-05-0816



SAIFI by APS Division* (Avg. Interruptions)

	2000	2001	2002	2003	2004	2005
Metro	1.29	1.17	0.98	1.17	1.05	1.11
Northeast	2.05	2.23	1.50	1.45	1.44	2.32
Northwest	1.95	1.89	1.24	1.80	1.06	1.48
Southeast	2.91	4.31	1.75	2.31	1.86	2.64
Southwest	1.15	2.03	0.79	1.91	1.49	1.38
SYSTEM	1.54	1.63	1.09	1.40	1.18	1.38

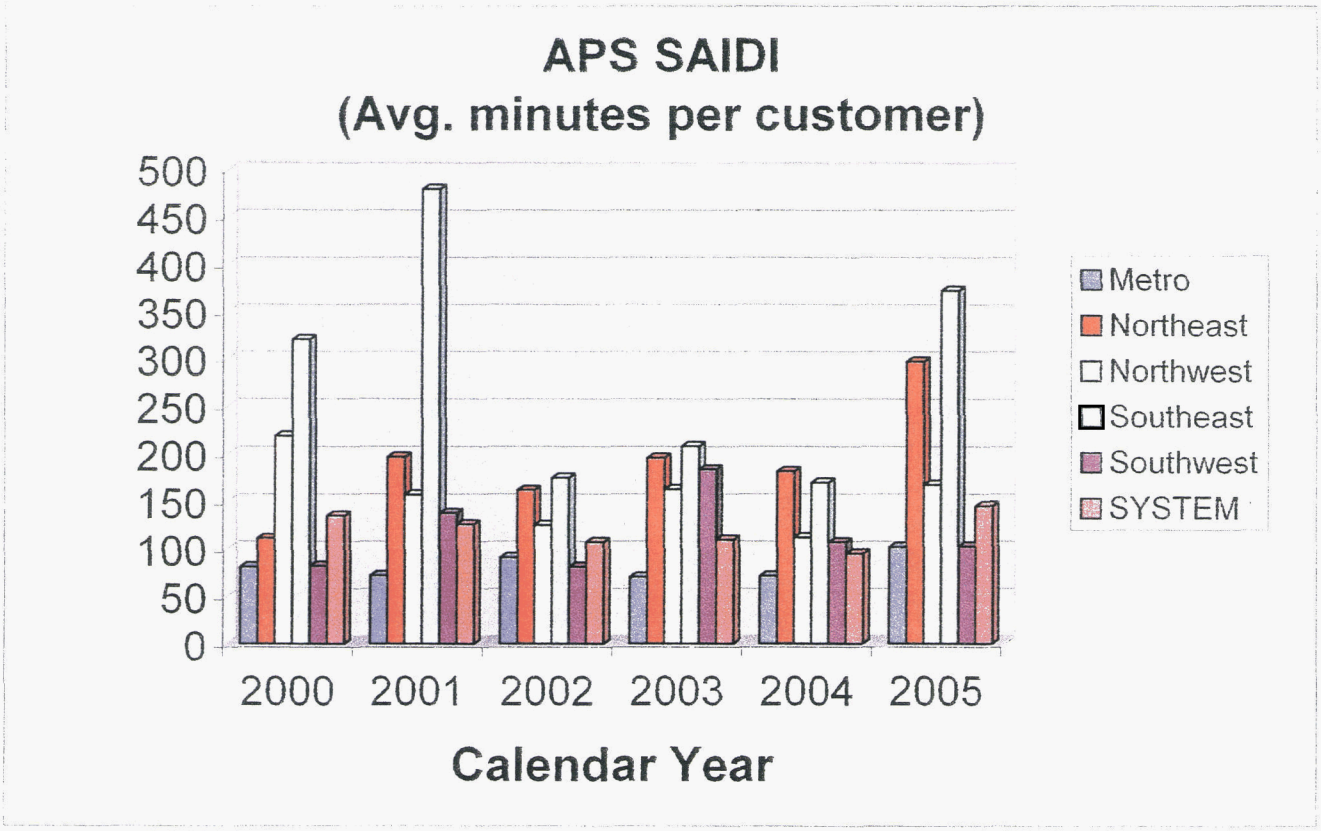
* 2000 - 2002 per APS response to Staff Data Request STF 8-54, Docket No. E-01345A-03-0347
2003 - 2005 per APS response to Staff Data Request JDS 2-3, Docket No. E-01345A-05-0816



SAIDI by APS Division* (Avg minutes per customer)

	2000	2001	2002	2003	2004	2005
Metro	81	72	91	70	71	102
Northeast	111	197	162	196	182	297
Northwest	219	157	125	163	112	168
Southeast	321	480	175	208	170	373
Southwest	82	138	81	184	107	102
SYSTEM	135	126	107	109	95	145

* 2000 - 2002 per APS response to Staff Data Request STF 8-54, Docket No. E-01345A-03-0347
2003 - 2005 per APS response to Staff Data Request JDS 2-3, Docket No. E-01345A-05-0816



CAIDI by APS Division* (Avg. minutes per outage)

	2000	2001	2002	2003	2004	2005
Metro	63	62	94	60	68	92
Northeast	54	88	108	135	126	128
Northwest	113	83	101	90	106	113
Southeast	111	111	100	90	91	141
Southwest	71	68	103	96	71	74
SYSTEM	88	78	97	78	81	105

* 2000 - 2002 per APS response to Staff Data Request STF 8-54, Docket No. E-01345A-03-0347
2003 - 2005 per APS response to Staff Data Request JDS 2-3, Docket No. E-01345A-05-0816

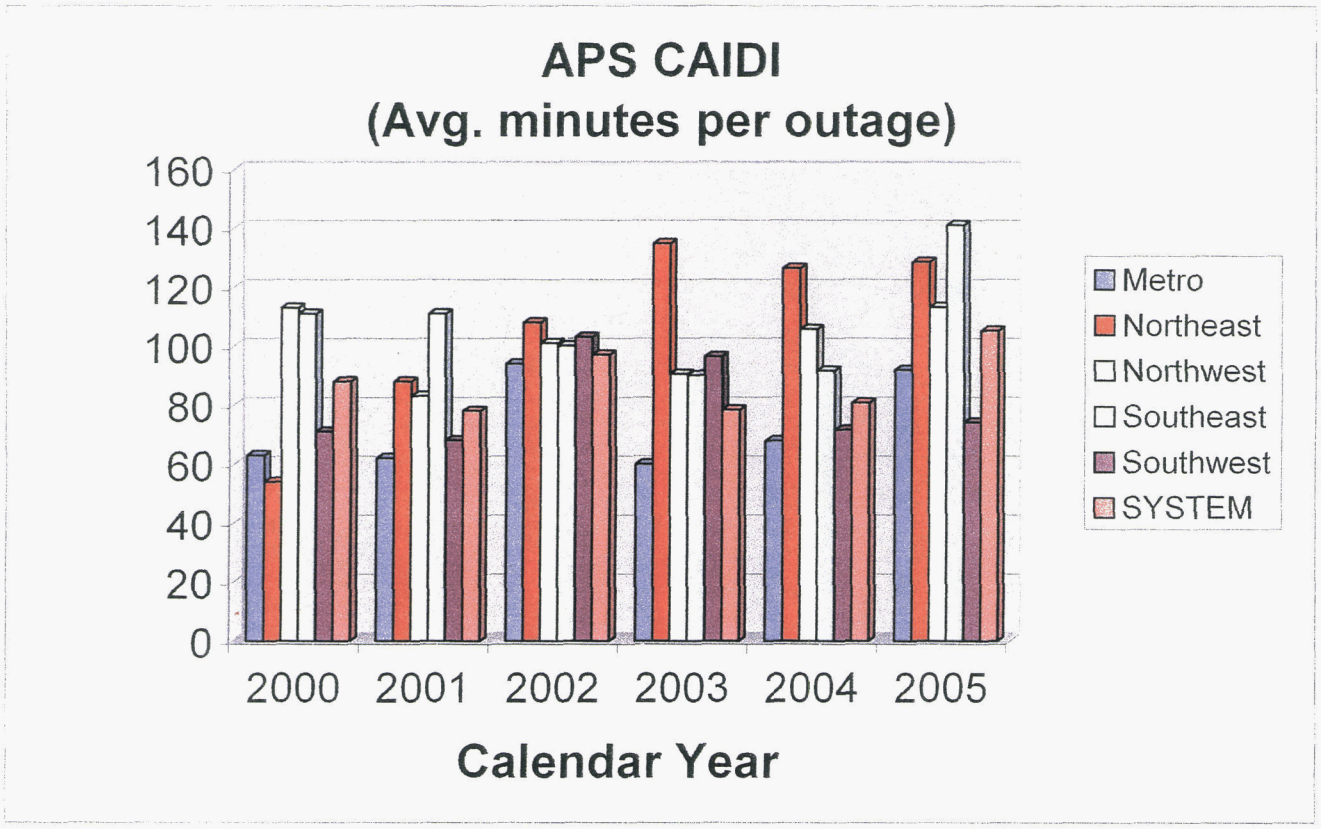


EXHIBIT
S-27
admitted

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS
REGARDING ARIZONA PUBLIC SERVICE COMPANY RATE CASE
DOCKET NO. E-01345A-05-0816
JUNE 19, 2006

JDS 2-7 APS filed a Reliability Review of Electric Service to Tribal Territories on October 7, 2005.[1] The reliability data was provided for 2002 through 2004. Please supply information updating the reliability data for 2005 and identify all system improvements steps completed by APS in 2005 to mitigate concerns regarding reliable service to tribal territories.

RESPONSE:

Please see the attached labeled as APS10387.

Witness: Steve Bischoff

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[1] APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437, October 5, 2005.

For the purpose of this update, the *Reliability Review of Electric Service to Tribal Territories*, dated October 7, 2005 will be referred to as "the report." All data has been reported utilizing one minute as the Sustained Outage threshold.

SAIFI, SAIDI, and CAIDI thresholds were reevaluated, using the same methodology as the report, but with the addition of the 2005 performance. The results are as follows:

	Single Transmission	Redundant Transmission	Overhead Distribution	Underground Distribution
SAIFI	7.68	3.33	7.25	2.48
SAIDI (Min)	477.4	158.8	486.4	103.4
CAIDI (Min)	156.4	140.5	176.9	121.9

Below is the performance summary for each feeder discussed in the report. Please refer to the report for the discussion of feeder boundaries, customer counts, transmission source, and distribution type (overhead or underground). An update of the action plan is included below. In addition, a discussion is provided for any new issues identified.

BEAR SPRINGS FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	7.00	2.00	9.00	7.00	6.25
SAIDI	540.0	120.0	60.0	25.8	186.5
CAIDI	77.1	60.0	6.7	3.6	36.9

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

CAMERON FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	8.00	2.95	9.17	7.00	6.78
SAIDI	581.0	901.2	260.4	25.8	442.1
CAIDI	72.6	305.3	28.4	3.6	102.5

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

The action plan for Cameron feeder #1 has been updated from the initial report.

In addition to adding a capacitor bank for voltage support, APS also intends to change out the Tuba City substation transformer, due to possible overload conditions. The plan and schedule have been discussed and concurred with by the Tribal Council. The revised completion scheduled for the Spring of 2007.

A contract has not yet been signed for the installation of a 69kV circuit breaker at Powell substation (WAPA), to replace an existing manual switch. The City of Page wants to determine if the change will be detrimental to their system and has asked the Arizona Municipal Power Users Association to study the request. The review is not yet completed. APS will continue to work with the City of Page and AMPUA to explore this opportunity.

The automating of switches, as discussed in the report, remains on schedule.

CAMERON FEEDER #3

	2002	2003	2004	2005	Avg.
SAIFI	7.04	2.01	9.00	7.00	6.26
SAIDI	500.2	639.6	224.2	25.8	347.5
CAIDI	71.1	318.3	24.9	3.6	104.5

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

The improvement plan discussed under Cameron feeder #1 will also benefit this feeder.

CAYWOOD FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	6.17	2.00	1.13	5.00	3.58
SAIDI	358.0	156.0	350.0	2298.0	790.5
CAIDI	58.1	78.0	308.8	459.6	226.13

All outages in 2005 were due to the loss of the ED-3 source to the Caywood substation. 98.27% of SAIFI, 98.05% of SAIDI, and 97.03% of CAIDI for years 2000-2005, is due to the loss of the ED-3 source to the Caywood substation. APS is discussing the reliability performance with ED-3 to identify opportunities for improvement.

CEMENT – VERDE 69KV LINE

	2002	2003	2004	2005	Avg.
SAIFI	0.00	0.00	0.00	0.00	0.00
SAIDI	0.0	0.0	0.0	0.0	0.0
CAIDI	0.0	0.0	0.0	0.0	0.0

The above reliability is better than the established reliability threshold for a single transmission source.

COCOPAH FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	0.06	6.86	5.19	2.35	3.62
SAIDI	5.9	557.1	216.4	106.8	221.6
CAIDI	92.2	81.2	41.7	45.0	65.0

The above reliability is better than the established reliability threshold for an overhead feeder with redundant transmission.

COPPER CANYON FEEDER #2

	2002	2003	2004	2005	Avg.
SAIFI	4.31	1.05	4.08	5.04	3.62
SAIDI	262.5	6.4	174.3	64.8	127.0
CAIDI	61.0	6.1	42.8	12.6	30.6

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

COTTONWOOD FEEDER #22

	2002	2003	2004	2005	Avg.
SAIFI	0.01	0.22	1.51	4.14	1.47
SAIDI	0.8	16.2	96.7	142.2	64.0
CAIDI	78.3	72.3	64.0	34.2	62.2

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

GILA BEND FEEDER #22

	2002	2003	2004	2005	Avg.
SAIFI	3.13	6.00	1.04	2.75	3.23
SAIDI	245.8	528.1	29.9	465.0	317.2
CAIDI	78.6	88.0	28.7	168.6	91.0

The high SAIDI for Gila Bend feeder #22 is due to response time. Crews were dispatched from the Buckeye service center and Ajo. This delayed restoration efforts. The local Gila Bend serviceman was unable to respond to the trouble calls. APS is determining the best locations to install devices that can be remotely operated to transfer load to adjacent feeders and sectionalize the problem, thus reducing SAIDI and CAIDI.

GRAY MOUNTAIN FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	1.69	0.07	4.32	6.07	3.04
SAIDI	670.3	8.6	473.6	217.8	342.6
CAIDI	396.7	120.0	109.6	36.0	165.6

The improvement plan is discussed under Cameron feeder #1.

HAMBLIN FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	7.00	2.00	10.00	4.00	5.75
SAIDI	540.0	6960.0	60.0	13.2	1893.3
CAIDI	77.1	3480.0	6.0	3.6	891.7

As discussed in the report, the spare transformer T1171 is still assigned and available as a spare to the Hamblin substation.

HAYFIELD DRAW FEEDER #2

	2002	2003	2004	2005	Avg.
SAIFI	0.78	2.27	0.71	6.35	2.53
SAIDI	38.3	55.6	235.3	267.6	149.2
CAIDI	48.9	24.5	331.3	42.0	111.7

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

KEAMS CANYON FEEDER #3

	2002	2003	2004	2005	Avg.
SAIFI	8.01	3.97	2.00	3.15	4.28
SAIDI	508.8	1030.6	711.5	235.2	621.5
CAIDI	63.5	259.9	355.6	74.4	188.4

As discussed in the report, fault locators have been installed on the Cholla – Keams Canyon 69kV line. SAIDI and CAIDI improved over previous years and in 2005 were well below the reliability thresholds for overhead feeders with a single transmission source.

KEAMS CANYON FEEDER #5

	2002	2003	2004	2005	Avg.
SAIFI	1.00	4.07	1.03	2.00	2.03
SAIDI	0.9	1044.3	672.9	132.6	462.7
CAIDI	0.9	256.5	651.2	66.0	243.7

As discussed in the report, fault locators have been installed on the Cholla – Keams Canyon 69kV line. SAIDI and CAIDI improved over previous years and in 2005 were well below the reliability thresholds for overhead feeders with a single transmission source.

LAGUNA FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	2.02	7.18	8.53	4.35	5.52
SAIDI	3.2	236.6	333.0	99.6	168.1
CAIDI	1.6	33.0	39.1	22.80	24.1

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

LAGUNA FEEDER #5

	2002	2003	2004	2005	Avg.
SAIFI	4.14	7.26	7.38	8.71	6.87
SAIDI	20.6	141.8	130.6	289.2	145.6
CAIDI	5.0	19.5	17.7	33.0	18.8

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

Due to an increasing SAIFI, a reliability patrol, a part of the maintenance process, was completed on 1/31/2006. The pole replacement is expected to continue into the fall.

MCGUIREVILLE FEEDER #10

	2002	2003	2004	2005	Avg.
SAIFI	0.74	0.19	0.45	4.43	1.45
SAIDI	341.4	42.7	51.1	228.0	165.8

CAIDI	459.6	230.5	114.4	51.6	214.0

In the report, APS had noted that McGuireville feeder #10 had exceeded the threshold for CAIDI. The cause was attributed to a single vegetation related incident in 2002. As can be seen from the data, the CAIDI has steadily improved.

MCGUIREVILLE FEEDER #14

	2002	2003	2004	2005	Avg.
SAIFI	0.09	0.03	0.05	3.03	0.80
SAIDI	19.1	1.8	1.6	81.6	26.0
CAIDI	5.83	1.37	3.20	27.0	9.4

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

MITRY FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	2.84	0.29	1.89	1.92	1.74
SAIDI	138.8	30.4	142.6	92.4	101.1
CAIDI	48.9	103.7	75.5	48.0	69.0

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

PAPAGO FEEDER #9

	2002	2003	2004	2005	Avg.
SAIFI	6.09	1.57	1.43	6.54	3.91
SAIDI	514.4	258.3	267.7	1003.8	511.1
CAIDI	84.5	165.0	186.5	153.6	147.4

99.92% of SAIDI in 2005 was due to loss of transmission source to Papago substation from ED-3. 87.40% of SAIFI, 98.01% of SAIDI, and 98.01% of CAIDI for years 2002-2005, is due to the loss of the ED-3 source to the Papago substation. APS is discussing the reliability performance with ED-3 to identify opportunities for improvement.

PAPAGO FEEDER #11

	2002	2003	2004	2005	Avg.
SAIFI	5.47	2.66	1.15	6.86	4.04
SAIDI	297.9	226.7	224.2	900.6	412.4
CAIDI	54.5	85.2	194.4	131.4	116.4

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

93.71% of SAIDI in 2005 was due to loss of transmission source to Papago substation from ED-3. 90.98% of SAIFI, 94.71% of SAIDI, and 94.71% of CAIDI for years 2002-2005, is due to the loss of the ED-3 source to the Papago substation. APS is discussing the reliability performance with ED-3 to identify opportunities for improvement.

PINAL FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	3.24	2.26	1.50	6.17	3.29
SAIDI	108.8	220.2	89.7	399.0	204.4
CAIDI	33.5	97.3	59.9	64.8	63.9

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

PRESCOTT CITY FEEDER #3

	2002	2003	2004	2005	Avg.
SAIFI	1.00	2.02	0.02	1.06	1.03
SAIDI	4.0	158.5	2.3	7.8	43.2
CAIDI	4.0	78.4	146.3	7.2	59.0

The above reliability is better than the established reliability threshold for underground feeders with redundant transmission sources.

SUNDOG FEEDER #5

	2002*	2003*	2004	2005	Avg.
SAIFI	2.09	0.33	0.29	0.02	0.68
SAIDI	68.4	43.5	29.4	1.20	35.6
CAIDI	32.8	133.8	102.6	88.2	89.4

* Previously served by Sundog feeder #12

The above reliability is better than the established reliability threshold for underground feeders with redundant transmission sources.

SUNSHINE FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	3.62	5.31	7.08	10.73	6.69
SAIDI	193.8	143.1	230.8	457.8	256.4
CAIDI	53.6	27.0	32.6	42.6	39.0

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

Although the SAIFI for Sunshine feeder #1 does not exceed the threshold in the report, the trend has been negative. The cause of the outages has been, almost exclusively, loss of the Coconino – Winslow 69kV line. On June 9, 2006, a reliability patrol discovered that the 69kV conductors that drop into the Sunshine substation transformer were making contact during heavy winds. A phase to phase fault at this location would cause the tripping of the Coconino – Winslow line. The separation between the conductors was increased to prevent future incidents.

THIRTY-SECOND STREET FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	0.34	1.71	2.48	2.48	1.75
SAIDI	16.2	248.0	561.9	1053.6	469.9

CAIDI	48.1	145.5	226.7	424.8	211.3

The cause of the high SAIDI and CAIDI in 2005 was due to a single extended outage. Twenty-four 69kV poles and five distribution poles had to be replaced as a result of storm damage that occurred on August 4, 2005.

TONALEA FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	7.00	2.00	9.00	7.00	6.25
SAIDI	660.0	200.0	160.0	25.8	261.5
CAIDI	94.3	100.0	17.8	3.6	53.9

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

The improvement plan discussed under Cameron feeder #1 will also benefit this feeder.

TONTO FEEDER #4

	2002	2003	2004	2005	Avg.
SAIFI	5.07	7.71	9.90	2.37	6.26
SAIDI	140.2	452.3	113.5	46.2	188.1
CAIDI	27.6	58.7	11.5	19.8	29.4

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

TUBA CITY FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	8.20	2.03	13.74	7.17	7.79
SAIDI	820.2	219.8	351.2	54.6	361.5
CAIDI	100.0	108.3	25.6	7.8	60.4

The installation of fault locators on the Black Mesa – Sandvig and Black Mesa – Tuba City 69kV lines were completed at the end of 2005. In addition, a line patrol and climbing inspection was also performed in 2005.

In addition, see discussion at Cameron feeder #1 above.

TUBA CITY FEEDER #3

	2002	2003	2004	2005	Avg.
SAIFI	7.04	3.08	9.20	8.30	6.91
SAIDI	725.7	265.5	262.2	106.2	339.9
CAIDI	103.1	86.1	28.4	12.6	57.6

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

For action plan update, see discussions at Cameron feeder #1 and Tuba City #1 feeder above.

VALLEY FARMS FEEDER #6

	2002	2003	2004	2005	Avg.
SAIFI	2.06	1.01	3.01	0.00	1.52
SAIDI	144.1	92.3	117.8	1.2	88.9
CAIDI	70.0	91.1	39.2	290.4	122.7

The above reliability is better than the established reliability threshold for overhead feeders with a single transmission source.

VISTA FEEDER #6

	2002	2003	2004	2005	Avg.
SAIFI	1.21	4.13	0.99	0.23	1.64
SAIDI	21.6	106.0	141.3	30.0	74.7
CAIDI	17.8	25.7	143.1	134.4	80.3

The above reliability is better than the established reliability threshold for overhead feeders with redundant transmission sources.

WHY FEEDER #1

	2002	2003	2004	2005	Avg.
SAIFI	3.02	7.01	3.04	15.09	7.04
SAIDI	45.3	1733.2	1226.1	1066.2	1017.7
CAIDI	15.0	247.4	403.1	70.8	184.1

The majority of Why outages are due to the loss of the Gila Bend – Why 69kV line.. APS is investigating the use of local generation to power the entire Why #1 feeder in the event of a transmission outage.