NEW APPLICATION

# Cover Sheet
## Arizona Corporation Commission
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Company/Case Name Arizona Public Service Company

Doing Business As (d/b/a) _____

Docket Number (s) E-01345A-03- E-01345A-03-0437

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**UTILITIES – NEW APPLICATION**

_____New CC&N
_____Rates
_____Interim Rates
_____Cancellation of CC&N
_____Deletion of CC&N
_____Extension of CC&N
_____Tariff (NEW)
_____Request for Arbitration
_____Full or Partially Arbitrated Interconnection Agreement
_____Voluntary Interconnection Agreement
_____Miscellaneous - Specify: _____

_____Main Extension
_____Contract/Agreements
_____Formal Complaint
_____Waiver/Rule Variance
_____Line Siting Committee Case
_____Small Water Company – Surcharge
_____Sale of Assets & Transfer of Ownership
_____Sale of Assets & Cancellation of CC&N
_____Fuel Adjuster/PGA
_____Merger
_____Financing

**UTILITIES – REVISIONS/AMENDMENTS TO PENDING OR APPROVED MATTERS**

_____Application:
Company _____
Docket Number _____

_____Tariff: (Promotional or Compliance)
(Circle One)
Decision No. _____
Docket No: _____

**SECURITIES or MISCELLANEOUS FILINGS**

_____Affidavit (Publication, Public Notice)
_____Comments
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_____Notice of Errata
_____Opposition
_____Petition

_____Request/Motion for Extension of Time
_____Request/Motion for a Hearing
_____Request/Motion for an Intervention
_____Miscellaneous Request/Motion
_____Request/Motion for a Re-hearing
_____Request/Motion to Continue Hearing
_____Request/Motion to Strike
_____Response
_____Testimony
_____Waiver
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Revised 10/15/02

ORIGINAL

NEW APPLICATION

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AZ CORP COMMISSION
DOCUMENT CONTROL

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

MARC SPITZER, Chairman
JIM IRVIN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
MIKE GLEASON

Arizona Corporation Commission
DOCKETED
JUN 27 2003
DOCKETED BY

E-01345A-03-0437

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | DOCKET NO. E-01345A-03-__<br><br>**APPLICATION** |

Pursuant to A.R.S. § 40-250, *et seq.*; A.A.C. R14-2-103; and Decision No. 61973 (October 6, 1999), Arizona Public Service Company ("APS" or "Company") hereby files an Application for a permanent increase of at least $175 million on annualized test year sales, or 9.8 percent on average, for its jurisdictional electric operations, to become effective on July 1, 2004.

The rate increase sought herein is required to enable the Company to maintain its credit ratings and attract new capital on reasonable terms, recover its costs of service, and permit APS to earn a fair rate of return on the fair value of its assets devoted to public service, which return will recover the Company's capital costs necessarily and prudently incurred in rendering adequate utility service to customers. The requested increase is necessary for APS to continue as the type of financially strong utility that can ensure APS customers continued reliable service, on demand, and at reasonable prices into the future.

APS is requesting that the Arizona Corporation Commission ("Commission") recognize the higher fuel and purchased power expenses that are being incurred by the Company; allow APS to include in rates at cost of service certain generation assets of Pinnacle West Energy Corporation ("PWEC");[1] permit APS to recover the $234 million write off taken under the 1999 Settlement Agreement, which was approved in Decision No. 61973; and provide for the recovery of all prudently incurred costs to comply with the Commission's Retail Electric Competition Rules, A.A.C. R14-2-1601, *et seq.* (the "Electric Competition Rules"), including the one-third of costs associated with the planned divestiture of generation from APS to PWEC that was not previously deferred pursuant to Decision No. 61973. Such amounts are included in the $175 million increase requested by this Application.

In addition, APS requests that the Commission approve depreciation and amortization rates and classifications for certain of the Company's tangible and intangible property and approve a specific accounting and ratemaking treatment of costs associated with asset retirement obligations under the recently implemented Statement of Financial Accounting Standards No. 143 ("SFAS 143").

Finally, APS is requesting Commission review of its long-term purchased power contract with PWEC, which was previously submitted to the Commission. This request is required by Section 5.3 of such contract. However, the need for such review and any subsequent Commission approval would be moot if the PWEC units are rate based as requested in this Application.

In support of this Application, the Company respectfully states as follows:

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[1] These units are Redhawk Combined Cycle Units 1 and 2, West Phoenix Combined Cycle Units 4 and 5, and Saguaro Combustion Turbine Unit 3 (collectively, the "PWEC Units").

I.

The Company is a corporation duly organized, existing and in good standing under the laws of the State of Arizona. Its principal place of business is 400 North Fifth Street, Phoenix, Arizona, 85004, and its post office address is P.O. Box 53999, Phoenix, Arizona 85072-3999.

II.

The Company is a public service corporation principally engaged in the generation, transmission and distribution of electricity for sale in Arizona. In conducting such business, the Company operates an interconnected and integrated electric utility system.

III.

All communications and correspondence concerning this Application, as well as communications and pleadings with respect thereto filed by other parties, should be served upon the following:

Thomas L. Mumaw
Karilee S. Ramaley
Pinnacle West Capital Corporation Law Department
P.O. Box 53999
Phoenix, Arizona 85072-3999
Attorneys for Arizona Public Service Company

Jeffrey B. Guldner
Faraz Sanei
Snell & Wilmer L.L.P.
400 East Van Buren
Phoenix, Arizona 85004-2202
Attorneys for Arizona Public Service Company

IV.

This Commission has jurisdiction to conduct public hearings to determine the fair value of the property of a public service corporation, to fix a just and reasonable rate of return thereon, and thereafter, to approve rate schedules designed to develop such return.

Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of such hearing, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery and other prehearing and hearing matters.

V.

Accompanying this Application are all of the relevant standard filing requirements ("SFRs") and rate design schedules described in A.A.C. R14-2-103[2] and the direct testimony and attachments of the following witnesses:

- Steven M. Wheeler
- Donald G. Robinson
- Ajit P. Bhatti
- Chris N. Froggatt
- Laura L. Rockenberger
- Charles E. Olson, Ph.D.
- William H. Hieronymus, Ph.D.
- John H. Landon, Ph.D.
- Alan Propper
- David J. Rumolo
- Kenneth Gordon, Ph.D.

VI.

The Company respectfully requests that this Commission set a date for a hearing on this Application such that new rates for the Company will become effective July 1, 2004. At the hearing conducted pursuant to this rate request, APS will establish and hereby alleges that:

(1) its current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service and are therefore no longer just and reasonable;

[2] This Application does not include SFR Schedule E-6 because such schedule applies only to a "combination utility" within the meaning of A.A.C. R14-2-103(A)(3)(q) which does not include APS.

(2) the requested increase is the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, for preservation of the Company's financial integrity and for the attraction of new capital investment on reasonable terms;

(3) the Company requires additional permanent revenue of at least $175 million based on annualized test period sales in order to continue to provide adequate and reliable electric service to its customers as required by law;

(4) the PWEC Units were prudently planned and constructed and are used and useful, and the acquisition of the PWEC Units and their inclusion in rates at cost of service is appropriate and in the best interests of APS customers;

(5) the recovery by APS of the $234 million write off taken pursuant to Decision No. 61973 and the recovery by APS of all prudently incurred costs to comply with the Commission's Electric Competition Rules, including the one-third of costs associated with the planned divestiture of generation from APS to PWEC that was not previously deferred pursuant to Decision No. 61973, is appropriate and warranted;

(6) Section 3.4 of the APS-PWEC Track B contract[3] requires APS to file an application for approval and full cost recovery within 60 days of contract execution because deliveries are contemplated to occur after January 1, 2006; to the extent that further action by APS is required, this Application constitutes such action as is required by Section 3.4 of

[3] This contract was submitted to the Commission in APS' May 27, 2003 Report on the Track B Solicitation Process and is discussed in the Independent Monitor's Final Report on Track B Solicitation filed on June 13, 2003.

the contract, and APS requests that any Commission order regarding such contract be consistent with the Company's rate application; and

(7) the requested increase and associated approvals fairly balance the interests of both APS' customers and its investors.

WHEREFORE, THE COMPANY RESPECTFULLY REQUESTS that the Commission:

A. Issue a procedural order establishing a date for hearing evidence concerning the Application and prescribing the time and form of notice to APS customers;

B. Issue a final order granting the Company the permanent rate increase sought herein;

C. Issue a final order authorizing APS' depreciation and amortization rates and classifications, and authorizing the requested treatment of asset retirement obligations resulting from SFAS 143; and

D. Grant the Company such other relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 27th day of June 2003.

PINNACLE WEST CAPITAL CORP.
Law Department

Thomas L. Mumaw
Karilee S. Ramaley

SNELL & WILMER L.L.P.

Jeffrey B. Guldner
Faraz Sanei

Attorneys for Arizona Public Service Company

ORIGINAL AND 13 COPIES OF THE FOREGOING
filed this 27th day of June 2003, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
PHOENIX, AZ 85007

1367385.1

# Schedules

A-1

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 12/31/2002
(Dollars in Thousands)

| Line No. | Description | Electric Original Cost | Electric RCND | Electric Fair Value | Line No. |
|---|---|---|---|---|---|
| 1. | Adjusted Rate Base | $ 4,207,476 (a) | $ 6,727,455 (a) | 5,467,466 | 1. |
| 2. | Adjusted Operating Income | 263,870 (b) | 263,870 (b) | 263,870 | 2. |
| 3. | Current Rate of Return | 6.27% | 3.92% | 4.83% | 3. |
| 4. | Required Operating Income | 364,788 | 364,788 | 364,788 | 4. |
| 5. | Required Rate of Return | 8.67% | 5.42% | 6.67% | 5. |
| 6. | Operating Income Deficiency | 100,918 | 100,918 | 100,918 | 6. |
| 7. | Gross Revenue Conversion Factor | 1.6529 (c) | 1.6529 (c) | 1.6529 (c) | 7. |
| 8. | Increase in Base Revenue Requirements | $ 166,807 | $ 166,807 | $ 166,807 | 8. |
| 9. | CRCC Surcharge (d) | 8,283 | 8,283 | 8,283 | 9. |
| 10. | Total Increase in Revenue Requirements | $ 175,090 | $ 175,090 | $ 175,090 | 10. |

| | Customer Classification | Projected Revenue Increase Due to Rates | % Increase | |
|---|---|---|---|---|
| 11. | Residential | 86,586 | 9.73% | 11. |
| 12. | General Service | 86,758 | 9.82% | 12. |
| 13. | Irrigation | 207 | 9.86% | 13. |
| 14. | Outdoor Lighting | 1,041 | 9.64% | 14. |
| 15. | Dusk-to-Dawn | 498 | 9.58% | 15. |
| 16. | Total | $ 175,090 | 9.77% | 16. |
| 17. | Total Sales to Ultimate Retail Customers | $ 1,791,584 (d) | | 17. |

Supporting Schedules
(a) B-1 (c) C-3
(b) C-1, page 2 (d) H-1

A-2

ARIZONA PUBLIC SERVICE COMPANY
Summary Results of Operations
Two Prior Years, Test Year and Projected Years
(Thousands of Dollars)

| Line No. | Description | Prior Years Year Ending 2000 (a) | Prior Years Year Ending 2001 (a) | Test Year Actual 12/31/2002 (a) | Test Year Adjusted 12/31/2002 (b) | Projected Year Present Rates 12/31/2003 (c) | Projected Year Present Rates 12/31/2004 (c) | Projected Year Proposed Rates 12/31/2004 (c) | Projected Year Present Rates 12/31/2005 (c) | Projected Year Proposed Rates 12/31/2005 (c) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Gross Revenues | $ 2,934,142 | $ 3,111,328 | $ 2,093,393 | $ 1,978,176 | $ 1,969,996 | $ 2,148,301 | $ 2,263,598 | $ 2,205,210 | $ 2,405,450 | 1. |
| 2. | Revenue Deductions & Operating Expenses | 2,487,906 | 2,712,350 | 1,764,393 | 1,713,172 | 1,667,927 | 1,798,414 | 1,837,180 | 1,872,584 | 1,954,397 | 2. |
| 3. | Operating Income | 446,236 | 398,978 | 329,000 | 265,004 | 302,069 | 349,887 | 426,418 | 332,626 | 451,053 | 3. |
| 4. | Other Income and (Deductions) | (6,545) | (15,280) | (8,041) | (8,041) | 960 | (1,667) | (1,667) | (8,411) | (8,411) | 4. |
| 5. | Interest Expense | 133,097 | 118,211 | 121,616 | 121,616 | 132,689 | 148,175 | 145,810 | 165,971 | 156,562 | 5. |
| 6. | Net Income | $ 306,594 | $ 265,487 | $ 199,343 | $ 135,347 | $ 170,340 | $ 200,045 | $ 278,941 | $ 158,244 | $ 286,080 | 6. |
| 7. | Earned Per Average Common Share* | $ 4.30 | $ 3.73 | $ 2.80 | $ 1.90 | N/A | N/A | N/A | N/A | N/A | 7. |
| 8. | Dividends Per Common Share* | $ 2.39 | $ 2.39 | $ 2.39 | $ 2.39 | N/A | N/A | N/A | N/A | N/A | 8. |
| 9. | Payout Ratio* | 55.6% | 64.1% | 85.4% | 125.8% | N/A | N/A | N/A | N/A | N/A | 9. |
| 10. | Return on Average Invested Capital | 11.1% | 9.3% | 7.6% | 6.3% | 6.9% | 7.1% | 8.6% | 6.2% | 8.3% | 10. |
| 11. | Return on Year End Capital | 10.7% | 9.1% | 7.7% | 6.4% | 6.6% | 6.8% | 8.2% | 6.0% | 8.1% | 11. |
| 12. | Return on Average Common Equity | 15.2% | 12.4% | 9.2% | 6.6% | 7.9% | 8.4% | 11.5% | 6.0% | 10.4% | 12. |
| 13. | Return on Year End Common Equity | 14.5% | 12.3% | 9.2% | 6.6% | 7.9% | 7.7% | 10.4% | 6.0% | 10.1% | 13. |
| 14. | Times Bond Interest Earned-Before Income Taxes | 3.8 | 3.6 | 2.9 | 2.6 | 2.5 | 2.7 | 3.4 | 2.2 | 3.3 | 14. |
| 15. | Times Total Interest & Preferred Dividends Earned-After Income Taxes | 2.6 | 2.5 | 2.1 | 1.8 | 1.9 | 2.0 | 2.4 | 1.7 | 2.4 | 15. |
| 16. | Adjusted Return on Avg. Common Equity | 12.4% | 8.0% | 7.9% | 5.4% | 6.7% | 7.8% | 11.0% | 6.0% | 10.4% | 16. |

Supporting Schedules:
(a) E-2
(b) C-1
(c) F-1

*Optional for projected year

A-3

ARIZONA PUBLIC SERVICE COMPANY
Summary of Capital Structure
Two Prior Years, Test Year and Projected Years
(Thousands of Dollars)

| Line No. | Description | Prior Years Year Ending 2000 (a) | Prior Years Year Ending 2001 (a) | Actual Test Year Ending 12/31/2002 (a) | Projected Year Present Rates Year Ending 12/31/2003 (b) | Projected Year Present Rates Year Ending 12/31/2004 (b) | Projected Year Proposed Rates Year Ending 12/31/2004 (b) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1. | Short-term Debt | 82,100 | 171,162 | - | 59,428 | 67,003 | 67,003 | 1. |
| 2. | Long-Term Debt | 2,057,174 | 2,074,525 | 2,220,843 | 2,637,848 | 2,710,162 | 2,630,656 | 2. |
| 3. | TOTAL DEBT | 2,139,274 | 2,245,687 | 2,220,843 | 2,697,276 | 2,777,165 | 2,697,659 | 3. |
| 4. | Preferred Stock | - | - | - | - | - | - | 4. |
| 5. | Common Equity | 2,119,768 | 2,150,690 | 2,159,312 | 2,162,314 | 2,612,299 | 2,690,969 | 5. |
| 6. | Total Capital | 4,259,042 | 4,396,377 | 4,380,155 | 4,859,590 | 5,389,464 | 5,388,628 | 6. |
| | Capitalization Ratios: | | | | | | | |
| 7. | Short-term Debt | 1.93% | 3.89% | 0.00% | 1.22% | 1.24% | 1.24% | 7. |
| 8. | Long-Term Debt | 48.30% | 47.19% | 50.70% | 54.28% | 50.29% | 48.82% | 8. |
| 9. | TOTAL DEBT | 50.23% | 51.08% | 50.70% | 55.50% | 51.53% | 50.06% | 9. |
| 10. | Preferred Stock | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 10. |
| 11. | Common Equity | 49.77% | 48.92% | 49.30% | 44.50% | 48.47% | 49.94% | 11. |
| | | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | |
| 12. | Weighted Cost of Short-Term Debt | 0.10% | 0.07% | 0.00% | 0.02% | 0.04% | 0.04% | 12. |
| 13. | Weighted Cost of Long-Term Debt | 3.31% | 3.00% | 3.06% | 3.17% | 2.91% | 2.91% | 13. |
| 14. | Weighted Cost of Senior Capital | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 14. |

Supporting Schedules:

(a) E-1
(b) D-1

A-4

ARIZONA PUBLIC SERVICE COMPANY
Construction Expenditures, Net Plant Placed in Service and Gross Utility Plant in Service
Two Prior Years, Test Year and Projected Years
(Thousands of Dollars)

| Line No. | Year | Construction Expenditures (a) | Net Plant Placed In Service (b) (c) | Gross Utility Plant in Service (c) | Line No. |
|---|---|---|---|---|---|
| 1. | Year Ended 2000 | $ 463,768 | $ 259,123 | $ 7,772,330 | 1. |
| 2. | Year Ended 2001 | 473,545 | 322,390 | 8,094,720 | 2. |
| 3. | Test Year - Year Ended 12/31/2002 | 498,285 | 392,154 | 8,486,874 | 3. |
| 4. | Projected Year - Year Ended 12/31/2003 | 407,642 | 335,463 | 8,822,337 | 4. |
| 5. | Projected Year - Year Ended 12/31/2004 | 382,898 | 1,476,239 | 10,298,576 | 5. |
| 6. | Projected Year - Year Ended 12/31/2005 | 523,325 | 447,724 | 10,746,300 | 6. |

Supporting Schedules:

(a) F-3 (Includes nuclear fuel costs.)
(b) E-5 (Test Year only.)

(c) Includes acquisition of Pinnacle West Energy Corporation ("PWEC") units in 2004.

A-5

ARIZONA PUBLIC SERVICE COMPANY
Summary Changes in Financial Position
Two Prior Years, Test Year and Projected Years
(Thousands of Dollars)

| Line No. | Year | Prior Years Year Ending 2000 | Prior Years Year Ending 2001 | Actual Test Year Ending 12/31/2002 | Projected Year Present Rates Year Ending 12/31/2003 | Projected Year Present Rates Year Ending 12/31/2004 | Projected Year Proposed Rates Year Ending 12/31/2004 | Projected Year Present Rates Year Ending 12/31/2005 | Projected Year Proposed Rates Year Ending 12/31/2005 | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (a) | (a) | (b) | (b) | (b) | (b) | (b) | |
| | Sources of Funds: | | | | | | | | | |
| 1. | Operations | $ 723,671 | $ 605,075 | $ 704,512 | $ 641,263 | $ 504,076 | $ 583,582 | $ 505,208 | $ 634,380 | 1. |
| 2. | Outside financing | (181,088) | (68,613) | (218,396) | 300,096 | (90,111) | (169,617) | 50,083 | (79,089) | 2. |
| 3. | Total funds Provided | 542,583 | 536,462 | 486,116 | 941,359 | 413,965 | 413,965 | 555,291 | 555,291 | 3. |
| | Application of Funds: | | | | | | | | | |
| 4. | Construction Expenditures | 464,368 | 465,360 | 490,156 | 411,899 | 386,883 | 386,883 | 528,710 | 528,710 | 4. |
| 5. | Other | 83,083 | 56,890 | (29,768) | 529,460 | 27,082 | 27,082 | 26,581 | 26,581 | 5. |
| 6. | Total Funds Applied | $ 547,451 | $ 522,250 | $ 460,388 | $ 941,359 | $ 413,965 | $ 413,965 | $ 555,291 | $ 555,291 | 6. |

Supporting Schedules:

(a) E-3
(b) F-2

B-1

ARIZONA PUBLIC SERVICE COMPANY
Summary of Original Cost and RCND Rate Base Elements
Total Company and ACC Jurisdictional
Test Year Ended 12/31/2002
(Dollars in Thousands)

| Line No. | Description | Original Cost Total Company (a) | Original Cost ACC (a) | | RCND Total Company (b) | RCND ACC (b) | | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ 8,486,874 | $ 8,203,305 | | $ 13,596,926 | $ 13,142,617 | | 1. |
| 2. | Less: Accumulated Depreciation & Amort. | 3,542,547 | 3,405,509 | | 5,677,664 | 5,458,032 | | 2. |
| 3. | Net Utility Plant in Service | 4,944,327 | 4,797,796 | | 7,919,262 | 7,684,585 | | 3. |
| | Deductions: | | | | | | | |
| 4. | Deferred Taxes | 1,292,375 | 1,268,546 | | 1,292,375 | 1,268,546 | | 4. |
| 5. | Investment Tax Credits | 4,040 | 4,033 | | 4,040 | 4,033 | | 5. |
| 6. | Customer Advances for Constr. | 45,513 | 45,513 | | 45,513 | 45,513 | | 6. |
| 7. | Customer Deposits | 39,865 | 39,865 | | 39,865 | 39,865 | | 7. |
| 8. | Pension Liability | 49,511 | 48,751 | | 49,511 | 48,751 | | 8. |
| 9. | Other Deferred Credits | 124,050 | 123,798 | | 124,050 | 123,798 | | 9. |
| 10. | Unamortized Gain-sale of Utility Plant | 59,484 | 59,381 | | 59,484 | 59,381 | | 10. |
| 11. | Total Deductions | 1,614,838 | 1,589,887 | | 1,614,838 | 1,589,887 | | 11. |
| | Additions: | | | | | | | |
| 12. | Regulatory Assets/Liabilities Net | 166,268 | 165,564 | | 166,268 | 165,564 | | 12. |
| 13. | Miscellaneous Deferred Debits | 27,379 | 26,959 | | 27,379 | 26,959 | | 13. |
| 14. | Depreciation Fund - Decommissioning | 194,440 | 191,608 | | 194,440 | 191,608 | | 14. |
| 15. | Allowance for Working Capital (d) | 175,713 | 172,423 | | 175,713 | 172,423 | | 15. |
| 16. | Total Additions | 563,800 | 556,554 | | 563,800 | 556,554 | | 16. |
| 17. | Total Rate Base Before Proforma Adjust. | 3,893,289 | 3,764,463 | | 6,868,224 | 6,651,252 | | 17. |
| 18. | Proforma Adjustments | 327,730 | 443,013 | | (123,896) | 76,203 | | 18. |
| 19. | Total Rate Base | $ 4,221,019 | $ 4,207,476 | (e) | $ 6,744,328 | $ 6,727,455 | (e) | 19. |

Supporting Schedules:
(a) B-2
(b) B-3
(c) B-5

Recap Schedules:
(e) A-1

B-2

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

| Line No. | Description | (1) Actual at End of Test Year 12/31/2002 (a) Total Co. (A) | (1) ACC (B) | (2) PWEC Units Total Co. (C) | (2) ACC (D) | (3) Remove Regulatory Assets Amortized under Prior Settlement Total Co. (E) | (3) ACC (F) |
|---|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ 8,486,874 | $ 8,203,305 | $ 1,021,886 | $ 1,015,393 | $ - | $ - |
| 2. | Less: Accumulated Depreciation & Amort. | 3,542,547 | 3,405,509 | 73,395 | 73,045 | - | - |
| 3. | Net Utility Plant in Service | 4,944,327 | 4,797,796 | 948,491 | 942,348 | - | - |
| 4. | Less: Total Deductions | 1,614,838 | 1,589,887 | 53,382 | 53,111 | (41,080) | (41,080) |
| 5. | Total Additions | 563,800 | 556,554 | - | - | (104,000) | (104,000) |
| 6. | Total Rate Base | $ 3,893,289 | $ 3,764,463 | $ 895,109 | $ 889,237 | $ (62,920) | $ (62,920) |

(2) Adjustment to Test Year rate base to include the Pinnacle West Energy Units including West Phoenix Combined Cycle Unit No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

(3) Adjustment to Test Year rate base to exclude certain net regulatory assets which, pursuant to the terms of the 1999 Settlement Agreement, will be fully amortized by June 30, 2004.

Supporting Schedules:
(a) E-1

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

| Line No. | Description | (4) Independent Spent Fuel Storage Installation ("ISFSI") Total Co. (G) | (4) ACC (H) | (5) Reversal of Settlement Write-Off Total Co. (I) | (5) ACC (J) | (6) Transmission Assets Total Co. (K) | (6) ACC (L) |
|---|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ - | $ - | $ - | $ - | $ (1,264,590) | $ (1,001,498) |
| 2. | Less: Accumulated Depreciation & Amort. | - | - | - | - | (499,955) | (380,603) |
| 3. | Net Utility Plant in Service | - | - | - | - | (764,635) | (620,895) |
| 4. | Less: Total Deductions | 1,707 | 1,682 | 92,430 | 92,430 | (115,992) | (93,445) |
| 5. | Total Additions | 4,321 | 4,258 | 234,000 | 234,000 | - | - |
| 6. | Total Rate Base | $ 2,614 | $ 2,576 | $ 141,570 | $ 141,570 | $ (648,643) | $ (527,450) |

(4) Adjustment to Test Year rate base to include the amount of System Benefits related ISFSI costs anticipated to be accrued between the end of the Test Year and June 30, 2004.

(5) Adjustment to Test Year rate base to restore the pre-tax $234 million deduction taken by the Company in consideration of benefits previously agreed to under the 1999 Settlement.

(6) Adjustment to Test Year rate base to remove transmission assets and generation plant functionalized to ancillary services consistent with FERC rules requiring APS to take transmission service and related ancillary services for the APS Standard Offer customers under the APS OATT.

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

| Line No. | Description | (7) Total Original Cost Rate Base Pro Forma Adjustments (b) Total Co. (M) | ACC (N) | (8) Adjusted at End of Test Year 12/31/2002 (b) Total Co. (O) | ACC (P) | Line No. |
|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ (242,704) | $ 13,895 | $ 8,244,170 | $ 8,217,200 | 1. |
| 2. | Less: Accumulated Depreciation & Amort. | (426,560) | (307,558) | 3,115,987 | 3,097,951 | 2. |
| 3. | Net Utility Plant in Service | 183,856 | 321,453 | 5,128,183 | 5,119,249 | 3. |
| 4. | Less: Total Deductions | (9,553) | 12,698 | 1,605,285 | 1,602,585 | 4. |
| 5. | Total Additions | 134,321 | 134,258 | 698,121 | 690,812 | 5. |
| 6. | Total Rate Base | $ 327,730 | $ 443,013 | $ 4,221,019 | $ 4,207,476 | 6. |

Recap Schedules:
(b) B-1

B-3

ARIZONA PUBLIC SERVICE COMPANY
RCND Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

| Line No. | Description | (1) Actual at End of Test Year 12/31/2002 (a) Total Co. (A) | (1) ACC (B) | (2) PWEC Units Total Co. (C) | (2) ACC (D) | (3) Remove Regulatory Assets Amortized under Prior Settlement Total Co. (E) | (3) ACC (F) |
|---|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ 13,596,926 | $ 13,142,617 | $ 1,023,292 | $ 1,016,790 | $ - | $ - |
| 2. | Less: Accumulated Depreciation & Amort. | 5,677,664 | 5,458,032 | 74,288 | 73,934 | - | - |
| 3. | Net Utility Plant in Service | 7,919,262 | 7,684,585 | 949,004 | 942,856 | - | - |
| 4. | Less: Total Deductions | 1,614,838 | 1,589,887 | 53,382 | 53,111 | (41,080) | (41,080) |
| 5. | Total Additions | 563,800 | 556,554 | - | - | (104,000) | (104,000) |
| 6. | Total Rate Base | $ 6,868,224 | $ 6,651,252 | $ 895,622 | $ 889,745 | $ (62,920) | $ (62,920) |

(2) Adjustment to Test Year rate base to include the Pinnacle West Energy Units including West Phoenix Combined Cycle Unit No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

(3) Adjustment to Test Year rate base to exclude certain net regulatory assets which, pursuant to the terms of the 1999 Settlement Agreement, will be fully amortized by June 30, 2004.

Supporting Schedules:
(a) B-4

ARIZONA PUBLIC SERVICE COMPANY
RCND Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

| Line No. | Description | (4) Independent Spent Fuel Storage Installation ("ISFSI") Total Co. (G) | (4) ACC (H) | (5) Reversal of Settlement Write-Off Total Co. (I) | (5) ACC (J) | (6) Transmission Assets Total Co. (K) | (6) ACC (L) |
|---|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ - | $ - | $ - | $ - | $ (2,018,055) | $ (1,598,208) |
| 2. | Less: Accumulated Depreciation & Amort. | - | - | - | - | (801,281) | (609,995) |
| 3. | Net Utility Plant in Service | - | - | - | - | (1,216,774) | (988,213) |
| 4. | Less: Total Deductions | 1,707 | 1,682 | 92,430 | 92,430 | (115,992) | (93,445) |
| 5. | Total Additions | 4,321 | 4,258 | 234,000 | 234,000 | - | - |
| 6. | Total Rate Base | $ 2,614 | $ 2,576 | $ 141,570 | $ 141,570 | $ (1,100,782) | $ (894,768) |

(4) Adjustment to Test Year rate base to include the amount of System Benefits related ISFSI costs anticipated to be accrued between the end of the Test Year and June 30, 2004.

(5) Adjustment to Test Year rate base to restore the pre-tax $234 million deduction taken by the Company in consideration of benefits previously agreed to under the 1999 Settlement.

(6) Adjustment to Test Year rate base to remove transmission assets and generation plant functionalized to ancillary services consistent with FERC rules requiring APS to take transmission service and related ancillary services for the Standard Offer customers under the APS OATT.

ARIZONA PUBLIC SERVICE COMPANY
RCND Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

| Line No. | Description | (7) Total RCND Rate Base Pro Forma Adjustments Total Co. (M) | (7) ACC (N) | (8) Adjusted at End of Test Year 12/31/2002 (b) Total Co. (O) | (8) ACC (P) | Line No. |
|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ (994,763) | ($581,418) | $ 12,602,163 | $ 12,561,199 | 1. |
| 2. | Less: Accumulated Depreciation & Amort. | (726,993) | (536,061) | 4,950,671 | 4,921,971 | 2. |
| 3. | Net Utility Plant in Service | (267,770) | (45,357) | 7,651,492 | 7,639,228 | 3. |
| 4. | Less: Total Deductions | (9,553) | 12,698 | 1,605,285 | 1,602,585 | 4. |
| 5. | Total Additions | 134,321 | 134,258 | 698,121 | 690,812 | 5. |
| 6. | Total Rate Base | $ (123,896) | $ 76,203 | $ 6,744,328 | $ 6,727,455 | 6. |

Recap Schedules:
(b) B-1

B-4

ARIZONA PUBLIC SERVICE COMPANY
RCND by Major Plant Accounts
Test Year Ended 12/31/02
(Thousands of Dollars)

| Line No. | Function | Plant Account | Description | RCN (a) | Condition Percent (b) | RCND (c) | Line No. |
|---|---|---|---|---|---|---|---|
| 1. | INTANGIBLES | 301 | Organization | $ 74 | 100.00% | $ 74 | 1. |
| 2. | | 302 | Franchises and consents | 884 | 40.18% | 355 | 2. |
| 3. | | 303 | Miscellaneous intangible plant | 201,550 | 50.53% | 101,843 | 3. |
| 4. | | | Subtotal | 202,508 | | 102,272 | 4. |
| 5. | PRODUCTION | 310 | Land and Land Rights | 3,206 | 100.00% | 3,206 | 5. |
| 6. | | 310 | Limit Term Land Rights | 89 | 45.33% | 40 | 6. |
| 7. | | 311 | Structures and improvements | 212,692 | 44.27% | 94,159 | 7. |
| 8. | | 312 | Boiler plant equipment | 1,763,288 | 44.65% | 787,308 | 8. |
| 9. | | 314 | Turbogenerator units | 527,950 | 33.91% | 179,028 | 9. |
| 10. | | 315 | Accessory electric equipment | 355,546 | 34.74% | 123,516 | 10. |
| 11. | | 316 | Miscellaneous power plant equip. | 88,665 | 59.33% | 52,605 | 11. |
| 12. | | 320 | Land and land rights | 3,400 | 100.00% | 3,400 | 12. |
| 13. | | 321 | Structures and improvements | 879,393 | 59.55% | 523,679 | 13. |
| 14. | | 322 | Reactor plant equipment | 1,352,385 | 57.19% | 773,430 | 14. |
| 15. | | 323 | Turbogenerator units | 492,053 | 59.73% | 293,903 | 15. |
| 16. | | 324 | Accessory electric equipment | 473,585 | 57.58% | 272,690 | 16. |
| 17. | | 325 | Misc power plant equip | 189,250 | 49.03% | 92,790 | 17. |
| 18. | | 330 | Limit Term Land Rights | 65 | 40.00% | 26 | 18. |
| 19. | | 331 | Structures and improvements | 1,163 | 0.00% | 0 | 19. |
| 20. | | 332 | Reservoirs, dams, and waterways | 10,601 | 0.00% | 0 | 20. |
| 21. | | 333 | Water wheels, turbines and generators | 1,943 | 0.00% | 0 | 21. |
| 22. | | 334 | Accessory electric equipment | 1,605 | 0.00% | 0 | 22. |
| 23. | | 335 | Miscellaneous power plant equip. | 259 | 0.00% | 0 | 23. |
| 24. | | 336 | Roads, railroads and bridges | 734 | 0.00% | 0 | 24. |
| 25. | | 340 | Land and land rights | 28 | 100.00% | 28 | 25. |
| 26. | | 341 | Structures and improvements | 16,529 | 43.20% | 7,141 | 26. |
| 27. | | 342 | Fuel holders, products, and accessories | 40,195 | 70.33% | 28,269 | 27. |
| 28. | | 343 | Prime movers | 116,835 | 11.86% | 13,857 | 28. |
| 29. | | 344 | Generators | 148,230 | 77.01% | 114,152 | 29. |
| 30. | | 345 | Accessory electric equipment | 44,549 | 52.24% | 23,272 | 30. |
| 31. | | 346 | Miscellaneous power plant equip. | 10,334 | 35.22% | 3,640 | 31. |
| 32. | | | Subtotal | 6,734,572 | | 3,390,139 | 32. |
| 33. | TRANSMISSION | 350 | Land and land rights | 32,009 | 100.00% | 32,009 | 33. |
| 34. | | 350 | Limit Term Land Rights | 18,799 | 57.02% | 10,719 | 34. |
| 35. | | 352 | Structures and improvements | 44,277 | 69.92% | 30,958 | 35. |
| 36. | | 353 | Station equipment | 799,655 | 58.66% | 469,077 | 36. |
| 37. | | 354 | Towers and fixtures | 271,421 | 44.93% | 121,949 | 37. |
| 38. | | 355 | Poles and fixtures | 316,497 | 67.90% | 214,901 | 38. |
| 39. | | 356 | Overhead conductors and devices | 560,601 | 58.80% | 329,633 | 39. |
| 40. | | 357 | Underground conduit | 17,941 | 71.38% | 12,806 | 40. |
| 41. | | 358 | Underground conductors and devices | 36,134 | 65.84% | 23,791 | 41. |
| 42. | | | SUBTOTAL | 2,097,334 | | 1,245,843 | 42. |
| 43. | DISTRIBUTION | 360 | Land and land rights | 26,030 | 100.00% | 26,030 | 43. |
| 44. | | 360 | Limit Term Land Rights | 725 | 25.24% | 183 | 44. |
| 45. | | 361 | Structures and improvements | 42,131 | 69.46% | 29,265 | 45. |
| 46. | | 362 | Station equipment | 322,369 | 66.66% | 214,891 | 46. |
| 47. | | 364 | Poles, towers, and fixtures | 529,061 | 70.64% | 373,729 | 47. |
| 48. | | 365 | Overhead conductors and devices | 363,653 | 73.08% | 265,757 | 48. |
| 49. | | 366 | Underground conduit | 516,658 | 87.90% | 454,143 | 49. |
| 50. | | 367 | Underground conductors and devices | 986,319 | 71.79% | 708,078 | 50. |
| 51. | | 368 | Line transformers | 585,096 | 61.30% | 358,664 | 51. |
| 52. | | 369 | Services | 320,772 | 64.44% | 206,705 | 52. |
| 53. | | 370 | Meters | 189,272 | 67.48% | 127,722 | 53. |
| 54. | | 371 | Installations on customers' premises | 44,452 | 65.60% | 29,161 | 54. |
| 55. | | 373 | Street lighting and signal systems | 88,382 | 65.69% | 58,058 | 55. |
| 56. | | | Subtotal | 4,014,920 | | 2,852,386 | 56. |

ARIZONA PUBLIC SERVICE COMPANY
RCND by Major Plant Accounts
Test Year Ended 12/31/02
(Thousands of Dollars)

| Line No. | Function | Plant Account | Description | RCN | Condition Percent | RCND | Line No. |
|---|---|---|---|---|---|---|---|
| | | | | (a) | (b) | (c) | |
| 57. | GENERAL | 389 | Land and land rights | 7,327 | 100.00% | 7,327 | 57. |
| 58. | | 390 | Structures and improvements | 164,648 | 66.32% | 109,195 | 58. |
| 59. | | 391 | Office furniture and equipment | 90,009 | 57.35% | 51,620 | 59. |
| 60. | | 391 | Capitalized Lease-Computer Equipment | 5,941 | 81.62% | 4,849 | 60. |
| 61. | | 392 | Transportation equipment | 34,941 | 27.47% | 9,598 | 61. |
| 62. | | 392 | Capitalized Lease-Transportation Equip. | 19,553 | 100.00% | 19,554 | 62. |
| 63. | | 393 | Stores equipment | 5,452 | 31.68% | 1,727 | 63. |
| 64. | | 394 | Tools, shop and garage equipment | 17,505 | 73.97% | 12,948 | 64. |
| 65. | | 395 | Laboratory equipment | 2,731 | 22.71% | 620 | 65. |
| 66. | | 396 | Power operated equipment | 38,790 | 33.43% | 12,968 | 66. |
| 67. | | 397 | Communication equipment | 158,534 | 61.25% | 97,102 | 67. |
| 68. | | 398 | Miscellaneous equipment | 2,161 | 51.57% | 1,114 | 68. |
| 69. | | | Subtotal | 547,592 | | 328,622 | 69. |
| 70. | | | Total Plant | $ 13,596,926 | | $ 7,919,262 | 70. |

Supporting Schedules
RCND Study

Recap Schedules
(a) B-3

B-4a

ARIZONA PUBLIC SERVICE COMPANY
Computation of RCND Rate Base Elements
Test Year Ended 12/31/02
(Dollars in Thousands)

| Line No. | | Description | Total * Company (b + c) (a) | ACC (b) | All Other (d + e) (c) | SCE 500KV (d) | Other (e) |
|---|---|---|---|---|---|---|---|
| 1. | A. | ORIGINAL COST: | | | | | |
| 2. | | Gross Utility Plant in Service | $ 8,486,874 | $8,203,305 | $ 283,569 | $ 51,829 | $ 231,740 |
| 3. | | Accumulated Depreciation & Amortization | 3,542,547 | 3,405,509 | 137,038 | 45,235 | 91,803 |
| 4. | | Net Utility Plant in Service | 4,944,327 | 4,797,796 | 146,531 | 6,594 | 139,937 |
| 5. | B. | RCND: | | | | | |
| 6. | | Reproduction Cost New | 13,596,926 | 13,142,617 | 454,309 | 213,611 | 240,698 |
| 7. | | Accumulated Depreciation from Sch B-1 | 5,677,664 | 5,458,032 | 219,632 | 186,434 | 33,198 |
| 8. | | Total RCND Plant in Service at 12/31/02 | 7,919,262 | 7,684,585 | 234,677 | 27,177 | 207,500 |
| 9. | | Deductions: | | | | | |
| 10. | | Deferred Taxes | 1,292,375 | 1,268,546 | 23,829 | - | 23,829 |
| 11. | | Investment Tax Credits | 4,040 | 4,033 | 7 | - | 7 |
| 12. | | Total Deferred Taxes and ITC | 1,296,415 | 1,272,579 | 23,836 | - | 23,836 |
| 13. | | Customer Advances for Construction | 45,513 | 45,513 | - | - | - |
| 14. | | Customer Deposits | 39,865 | 39,865 | - | - | - |
| 15 | | Pension Liability | 49,511 | 48,751 | 760 | - | 760 |
| 16 | | Other Deferred Credits | 124,050 | 123,798 | 252 | - | 252 |
| 17 | | Deferred Gains for Sale of Util. Plant | 59,484 | 59,381 | 103 | - | 103 |
| 18 | | Total Deductions | 1,614,838 | 1,589,887 | 24,951 | - | 24,951 |
| 19 | | Additions: | | | | | |
| 20 | | Regulatory Assets/Liabilities Net | 166,268 | 165,564 | 704 | - | 704 |
| 21 | | Miscellaneous Deferred Debits | 27,379 | 26,959 | 420 | - | 420 |
| 22 | | Depreciation Fund - Decommissioning | 194,440 | 191,608 | 2,832 | - | 2,832 |
| 23 | | Allowance for Working Capital | 175,713 | 172,423 | 3,290 | - | 3,290 |
| 24 | | Total Additions | 563,800 | 556,554 | 7,246 | - | 7,246 |
| 25 | | Total RCND Rate Base Before Proforma Adj. | 6,868,224 | 6,651,252 | 216,972 | 27,177 | 189,795 |
| 26 | | Proforma Adjustments | (123,896) | 76,203 | (200,099) | (27,177) | (172,922) |
| 27 | | Total RCND Rate Base | $ 6,744,328 | $6,727,455 | $ 16,873 | $ - | $ 16,873 |

Supporting Schedules:
For Lines 2, 3, 9-23, Col. (a): See Schedule B-1, Column (a).
For Lines 2, 3, 9-23, Col. (b): See Schedule B-1, Column (b).
For Line 6, Col. (a): See Schedule b-4, Column (a) page 2 of 2.
For Line 8, Col. (a): See Schedule b-4, Column (c) page 2 of 2.

* - Includes SCE 500KV

B-5

ARIZONA PUBLIC SERVICE COMPANY
Computation of Working Capital
Test Year Ended 12/31/02
(Dollars in Thousands)

| Line No. | Description | Amount | Line No. |
|---|---|---|---|
| 1. | Cash Working Capital (a) | $ 54,098 | 1. |
| 2. | Materials and Supplies (b) | 79,985 | 2. |
| 3. | Fuel - Coal and Oil (b) | 28,185 | 3. |
| 4. | Fuel - Nuclear, Net (b) (c) | 7,466 | 4. |
| 5. | Prepayments (b) | 5,979 | 5. |
| 6. | Total Working Capital Allowance (d) | $ 175,713 | 6. |

Supporting Schedules:
(a) Lead-Lag Study.
(b) E-1
(c) B-5, Page 2 of 2

Recap Schedules:
(d) B-1

ARIZONA PUBLIC SERVICE COMPANY
Nuclear Fuel Balances
Test Year Ended 12/31/02

| Line No. | Description | Amount | Line No. |
|---|---|---|---|
| 1. | Nuclear Fuel in Reactor: | | 1. |
| 2. | Palo Verde Unit 1 | $ 36,407,633 | 2. |
| 3. | Palo Verde Unit 2 | 36,598,656 | 3. |
| 4. | Palo Verde Unit 3 | 35,483,712 | 4. |
| 5. | Total Nuclear Fuel in Reactor | 108,490,001 | 5. |
| 6. | Amortization of Nuclear Fuel | | 6. |
| 7. | Palo Verde Unit 1 | 15,017,693 | 7. |
| 8. | Palo Verde Unit 2 | 19,113,964 | 8. |
| 9. | Palo Verde Unit 3 | 24,761,771 | 9. |
| | Dry Cask Storage | 43,927,988 | |
| 10. | Total Amortization of Nuclear Fuel | 102,821,416 | 10. |
| 11. | Nuclear Fuel in Reactor (Net of Amortization) | | 11. |
| 12. | Palo Verde Unit 1 | 21,389,940 | 12. |
| 13. | Palo Verde Unit 2 | 17,484,692 | 13. |
| 14. | Palo Verde Unit 3 | 10,721,941 | 14. |
| | Dry Cask Storage (Amortization) | (43,927,988) | |
| 15. | Total Nuclear Fuel in Reactor (Net) | 5,668,585 | 15. |
| 16. | Nuclear Fuel in Stock: | | 16. |
| 17. | Palo Verde Unit 1 | 367,000 | 17. |
| 18. | Palo Verde Unit 2 | 1,365,333 | 18. |
| 19. | Palo Verde Unit 3 | 65,366 | 19. |
| 20. | Total Nuclear Fuel in Stock | 1,797,699 | 20. |
| 21. | Total Nuclear Fuel - Net (a) | $ 7,466,284 | 21. |

Supporting Schedules:
N/A

Recap Schedules:
(a) B-5, Page 1 of 2

C-1

ARIZONA PUBLIC SERVICE COMPANY
Total Company
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 12/31/02

(Dollars in Thousands)

| Line No. | Description | Total Company: Actual For The Test Year Ended 12/31/02 (a) | Proforma Adjustments (b) | Test Year Results After Proforma Adjustments (c) | Line No. |
|---|---|---|---|---|---|
| 1. | Electric operating revenues | $ 2,093,393 | $ (115,217) | $ 1,978,176 | 1. |
| 2. | Purchased power and fuel costs | 628,030 | (59,161) | 568,869 | 2. |
| 3. | Operating revenues less purchased power and fuel costs | 1,465,363 | (56,056) | 1,409,307 | 3. |
| 4. | Other operating expenses: | | | | 4. |
| 5. | Operations and maintenance | 495,845 | 120,216 | 616,061 | 5. |
| 6. | Depreciation and amortization | 399,640 | (68,148) | 331,492 | 6. |
| 7. | Income taxes | 132,953 | (46,347) | 86,606 | 7. |
| 8. | Other taxes | 107,925 | 2,219 | 110,144 | 8. |
| 9. | Total | 1,136,363 | 7,940 | 1,144,303 | 9. |
| 10. | Operating income | 329,000 | (63,996) | 265,004 | 10. |
| 11. | Other income (deductions): | | | | 11. |
| 12. | Income taxes | 6,148 | - | 6,148 | 12. |
| 13. | Other income | 5,149 | - | 5,149 | 13. |
| 14. | Other expense | (19,338) | - | (19,338) | 14. |
| 15. | Total | (8,041) | - | (8,041) | 15. |
| 16. | Income before interest deductions | 320,959 | (63,996) | 256,963 | 16. |
| 17. | Interest deductions: | | | | 17. |
| 18. | Interest on long-term debt | 128,462 | - | 128,462 | 18. |
| 19. | Interest on short-term borrowings | 5,416 | - | 5,416 | 19. |
| 20. | Debt discount, premium and expense | 2,888 | - | 2,888 | 20. |
| 21. | Capitalized interest | (15,150) | - | (15,150) | 21. |
| 22. | Total | 121,616 | - | 121,616 | 22. |
| 23. | Net income | $ 199,343 | $ (63,996) | $ 135,347 | 23. |

Supporting Schedules:
(a) E-2
(b) C-2

Recap Schedules:
(c) A-2

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 12/31/02

(Dollars in Thousands)

| Line No. | Description | ACC Jurisdiction: Actual For The Test Year Ended 12/31/02 | Proforma Adjustments (a) | Test Year Results After Proforma Adjustments (b) | Line No. |
|---|---|---|---|---|---|
| 1. | Electric Operating Revenues | $ 2,051,730 | $ (111,584) | $ 1,940,146 | 1. |
| 2. | Purchased power and fuel costs | 616,873 | (56,994) | 559,879 | 2. |
| 3. | Operating revenues less purchased power and fuel costs | 1,434,857 | (54,590) | 1,380,267 | 3. |
| 4. | Other Operating Expenses: | | | | 4. |
| 5. | Operations and maintenance | 489,041 | 101,032 | 590,073 | 5. |
| 6. | Depreciation and amortization | 393,035 | (63,052) | 329,983 | 6. |
| 7. | Income taxes | 129,307 | (43,163) | 86,144 | 7. |
| 8. | Other taxes | 104,205 | 5,992 | 110,197 | 8. |
| 9. | Total | 1,115,588 | 809 | 1,116,397 | 9. |
| 10. | Operating Income | $ 319,269 | $ (55,399) | $ 263,870 | 10. |

Supporting Schedules:
(a) C-2

Recap Schedules:
(b) A-1

C-2

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

| Line No. | Description | (1) Exclude Regulatory Assessments and Franchise Fees | | (2) Annualize 7/1/03 ACC Rate Levels | | (3) Normalize Weather Conditions | |
|---|---|---|---|---|---|---|---|
| | | Total Co. (A) | ACC (B) | Total Co. (C) | ACC (D) | Total Co. (E) | ACC (F) |
| 1. | Electric Operating Revenues | $ (31,707) | $ (31,707) | $ (37,005) | $ (37,005) | $ (5,204) | $ (5,204) |
| 2. | Purchased Power and Fuel Costs | - | - | - | - | (827) | (827) |
| 3. | Oper Rev Less Purch Pwr & Fuel Costs | (31,707) | (31,707) | (37,005) | (37,005) | (4,377) | (4,377) |
| | Other Operating Expenses: | | | | | | |
| 4. | Operations Excluding Fuel Expense | (31,707) | (31,707) | - | - | (218) | (218) |
| 5. | Maintenance | - | - | - | - | - | - |
| 6. | Subtotal | (31,707) | (31,707) | - | - | (218) | (218) |
| 7. | Depreciation and Amortization | - | - | - | - | - | - |
| 8. | Amortization of Gain | - | - | - | - | - | - |
| 9. | Administrative and General | - | - | - | - | - | - |
| 10. | Other Taxes | - | - | - | - | - | - |
| 11. | Total | (31,707) | (31,707) | - | - | (218) | (218) |
| 12. | Operating Income Before Income Tax | - | - | (37,005) | (37,005) | (4,159) | (4,159) |
| 13. | Interest Expense | - | - | - | - | - | - |
| 14. | Taxable Income | - | - | (37,005) | (37,005) | (4,159) | (4,159) |
| 15. | Current Income Tax Rate - 39.5% | - | - | (14,617) | (14,617) | (1,643) | (1,643) |
| 16. | Operating Income (line 12 - line 15) | $ - | $ - | $ (22,388) | $ (22,388) | $ (2,516) | $ (2,516) |

(1) Adjustment to Test Year operations to exclude regulatory assessments and franchise fees from both operating revenue and operating expense.

(2) Adjustment to Test Year operations to reflect the annualization of ACC rate levels for the 7/1/02 and 7/1/03 rate decreases.

(3) Adjustment to Test Year operations to reflect normal weather conditions for the ten years ended December 31, 2002.

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

| Line No. | Description | (4) Annualize Customer Levels to Year-End 2002 Total Co. (G) | (4) ACC (H) | (5) Schedule 1 Changes Total Co. (I) | (5) ACC (J) | (6) Base Rate Component for EPS Total Co. (K) | (6) ACC (L) |
|---|---|---|---|---|---|---|---|
| 1. | Electric Operating Revenues | $ 20,971 | $ 20,971 | $ 79 | $ 79 | $ 5,263 | $ 5,263 |
| 2. | Purchased Power and Fuel Costs | 4,779 | 4,779 | - | - | - | - |
| 3. | Oper Rev Less Purch Pwr & Fuel Costs | 16,192 | 16,192 | 79 | 79 | 5,263 | 5,263 |
| | Other Operating Expenses: | | | | | | |
| 4. | Operations Excluding Fuel Expense | 1,622 | 1,622 | (3) | (3) | 6,000 | 6,000 |
| 5. | Maintenance | - | - | - | - | - | - |
| 6. | Subtotal | 1,622 | 1,622 | (3) | (3) | 6,000 | 6,000 |
| 7. | Depreciation and Amortization | - | - | - | - | - | - |
| 8. | Amortization of Gain | - | - | - | - | - | - |
| 9. | Administrative and General | - | - | - | - | - | - |
| 10. | Other Taxes | - | - | - | - | - | - |
| 11. | Total | 1,622 | 1,622 | (3) | (3) | 6,000 | 6,000 |
| 12. | Operating Income Before Income Tax | 14,570 | 14,570 | 82 | 82 | (737) | (737) |
| 13. | Interest Expense | - | - | - | - | - | - |
| 14. | Taxable Income | 14,570 | 14,570 | 82 | 82 | (737) | (737) |
| 15. | Current Income Tax Rate - 39.5% | 5,755 | 5,755 | 32 | 32 | (291) | (291) |
| 16. | Operating Income (line 12 - line 15) | $ 8,815 | $ 8,815 | $ 50 | $ 50 | $ (446) | $ (446) |

(4) Adjustment to Test Year operations to reflect the annualization of customer levels at December 31, 2002.

(5) Adjustment to Test Year operations to reflect proposed revenue-related changes to Schedule 1.

(6) Adjustment to Test Year operations related to the base rate component of the Company's System Benefits Charge which is used to fund the Environmental Portfolio Standard. Revenue is adjusted to reverse Test Year entries to contributions in aid of construction and to include the expenses allowed by the Commission.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

| Line No. | Description | (7) Base Fuel and Purchased Power Total Co. (M) | (7) Base Fuel and Purchased Power ACC (N) | (8) Normalize Off-System Sales Total Co. (O) | (8) Normalize Off-System Sales ACC (P) | (9) PWEC Units Total Co. (Q) | (9) PWEC Units ACC (R) |
|---|---|---|---|---|---|---|---|
| 1. | Electric Operating Revenues | $ - | $ - | $ (128,200) | $ (126,332) | $ 56,779 | $ 56,237 |
| 2. | Purchased Power and Fuel Costs | 120,584 | 120,584 | (151,868) | (149,655) | (34,970) | (34,970) |
| 3. | Oper Rev Less Purch Pwr & Fuel Costs | (120,584) | (120,584) | 23,668 | 23,323 | 91,749 | 91,207 |
| | Other Operating Expenses: | | | | | | |
| 4. | Operations Excluding Fuel Expense | - | - | - | - | 14,110 | 14,086 |
| 5. | Maintenance | - | - | - | - | 18,549 | 18,390 |
| 6. | Subtotal | - | - | - | - | 32,659 | 32,476 |
| 7. | Depreciation and Amortization | - | - | - | - | 41,541 | 41,469 |
| 8. | Amortization of Gain | - | - | - | - | - | - |
| 9. | Administrative and General | - | - | - | - | 8,797 | 8,782 |
| 10. | Other Taxes | - | - | - | - | 11,256 | 11,184 |
| 11. | Total | - | - | - | - | 94,253 | 93,911 |
| 12. | Operating Income Before Income Tax | (120,584) | (120,584) | 23,668 | 23,323 | (2,504) | (2,704) |
| 13. | Interest Expense | - | - | - | - | 36,179 | 35,977 |
| 14. | Taxable Income | (120,584) | (120,584) | 23,668 | 23,323 | (38,683) | (38,681) |
| 15. | Current Income Tax Rate - 39.5% | (47,631) | (47,631) | 9,349 | 9,213 | (15,280) | (15,279) |
| 16. | Operating Income (line 12 - line 15) | $ (72,953) | $ (72,953) | $ 14,319 | $ 14,110 | $ 12,776 | $ 12,575 |

(7) Adjustment to Test Year operations to include 2003 base fuel and purchased power cents/kWh costs at adjusted 2002 consumption.

(8) Adjustment to Test Year operations to include off-system revenues consistent with the Base Fuel and Purchased Power pro forma adjustment.

(9) Adjustment to Test Year operations to include the Pinnacle West Energy Units including West Phoenix Combined Cycle No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

| Line No. | Description | (10) Annualize Payroll Total Co. (S) | (10) Annualize Payroll ACC (T) | (11) Employee Severance Total Co. (U) | (11) Employee Severance ACC (V) | (12) Employee Benefits Adjustment Total Co. (W) | (12) Employee Benefits Adjustment ACC (X) |
|---|---|---|---|---|---|---|---|
| 1. | Electric Operating Revenues | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Purchased Power and Fuel Costs | 7 | 7 | - | - | 253 | 249 |
| 3. | Oper Rev Less Purch Pwr & Fuel Costs | (7) | (7) | - | - | (253) | (249) |
| | Other Operating Expenses: | | | | | | |
| 4. | Operations Excluding Fuel Expense | 851 | 843 | (23,155) | (22,800) | 18,623 | 18,375 |
| 5. | Maintenance | 173 | 171 | - | - | 5,942 | 5,863 |
| 6. | Subtotal | 1,024 | 1,014 | (23,155) | (22,800) | 24,565 | 24,238 |
| 7. | Depreciation and Amortization | - | - | - | - | - | - |
| 8. | Amortization of Gain | - | - | - | - | - | - |
| 9. | Administrative and General | - | - | - | - | - | - |
| 10. | Other Taxes | - | - | - | - | - | - |
| 11. | Total | 1,024 | 1,014 | (23,155) | (22,800) | 24,565 | 24,238 |
| 12. | Operating Income Before Income Tax | (1,031) | (1,021) | 23,155 | 22,800 | (24,818) | (24,487) |
| 13. | Interest Expense | - | - | - | - | - | - |
| 14. | Taxable Income | (1,031) | (1,021) | 23,155 | 22,800 | (24,818) | (24,487) |
| 15. | Current Income Tax Rate - 39.5% | (406) | (403) | 9,146 | 9,006 | (9,803) | (9,672) |
| 16. | Operating Income (line 12 - line 15) | $ (625) | $ (618) | $ 14,009 | $ 13,794 | $ (15,015) | $ (14,815) |

(10) Adjustment to Test Year operations to reflect the annualization of payroll and payroll taxes to employee levels at December 31, 2002 and salary levels at March 2003.

(11) Adjustment to Test Year operations to reflect a three-year levelization of expenses incurred during the Test Year related to a voluntary severance and early retirement program offered by the Company.

(12) Adjustment to Test Year operations to reflect increased employee benefits expenses.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

| Line No. | Description | (13) On-Going Direct Access Expense Total Co. (Y) | (13) On-Going Direct Access Expense ACC (Z) | (14) On-Going Independent Spent Fuel Storage Installation ("ISFSI") Expense Total Co. (AA) | (14) On-Going Independent Spent Fuel Storage Installation ("ISFSI") Expense ACC (BB) | (15) Transmission Expenses Total Co. (CC) | (15) Transmission Expenses ACC (DD) |
|---|---|---|---|---|---|---|---|
| 1. | Electric Operating Revenues | $ - | $ - | $ - | $ - | $ (2,310) | $ - |
| 2. | Purchased Power and Fuel Costs | - | - | 2,881 | 2,839 | - | - |
| 3. | Oper Rev Less Purch Pwr & Fuel Costs | - | - | (2,881) | (2,839) | (2,310) | - |
| | Other Operating Expenses: | | | | | | |
| 4. | Operations Excluding Fuel Expense | 1,477 | 1,477 | - | - | 112,362 | 92,266 |
| 5. | Maintenance | - | - | - | - | (610) | (483) |
| 6. | Subtotal | 1,477 | 1,477 | - | - | 111,752 | 91,783 |
| 7. | Depreciation and Amortization | - | - | - | - | (29,163) | (23,101) |
| 8. | Amortization of Gain | - | - | - | - | - | - |
| 9. | Administrative and General | - | - | - | - | (5,814) | (4,932) |
| 10. | Other Taxes | - | - | - | - | (19,236) | (15,283) |
| 11. | Total | 1,477 | 1,477 | - | - | 57,539 | 48,467 |
| 12. | Operating Income Before Income Tax | (1,477) | (1,477) | (2,881) | (2,839) | (59,849) | (48,467) |
| 13. | Interest Expense | - | - | - | - | (18,756) | (15,252) |
| 14. | Taxable Income | (1,477) | (1,477) | (2,881) | (2,839) | (41,093) | (33,215) |
| 15. | Current Income Tax Rate - 39.5% | (583) | (583) | (1,138) | (1,121) | (16,232) | (13,120) |
| 16. | Operating Income (line 12 - line 15) | $ (894) | $ (894) | $ (1,743) | $ (1,718) | $ (43,617) | $ (35,347) |

(13) Adjustment to Test Year operations to include on-going costs of compliance with the Electric Competition Rules. Such costs were previously deferred and therefore were not included in Test Year operating expenses.

(14) Adjustment to Test Year operations to reflect the on-going costs of ISFSI. Such System Benefits related costs were previously deferred and therefore were not included in Test Year operating expenses.

(15) Adjustment to Test Year operations to remove transmission and ancillary services-related expenses from base rates and include OATT costs as an expense consistent with FERC rules requiring APS to take transmission and related ancillary services for the APS Standard Offer customers under the APS OATT.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

| Line No. | Description | (16) Interest on Customer Deposits Total Co. (EE) | (16) Interest on Customer Deposits ACC (FF) | (17) Normalize Non-nuclear Maintenance Expense Total Co. (GG) | (17) Normalize Non-nuclear Maintenance Expense ACC (HH) | (18) Normalize Nuclear Maintenance Expense Total Co. (II) | (18) Normalize Nuclear Maintenance Expense ACC (JJ) |
|---|---|---|---|---|---|---|---|
| 1. | Electric Operating Revenues | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Purchased Power and Fuel Costs | - | - | - | - | - | - |
| 3. | Oper Rev Less Purch Pwr & Fuel Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 4. | Operations Excluding Fuel Expense | 875 | 875 | - | - | - | - |
| 5. | Maintenance | - | - | (6,014) | (5,933) | (945) | (935) |
| 6. | Subtotal | 875 | 875 | (6,014) | (5,933) | (945) | (935) |
| 7. | Depreciation and Amortization | - | - | - | - | - | - |
| 8. | Amortization of Gain | - | - | - | - | - | - |
| 9. | Administrative and General | - | - | - | - | - | - |
| 10. | Other Taxes | - | - | - | - | - | - |
| 11. | Total | 875 | 875 | (6,014) | (5,933) | (945) | (935) |
| 12. | Operating Income Before Income Tax | (875) | (875) | 6,014 | 5,933 | 945 | 935 |
| 13. | Interest Expense | - | - | - | - | - | - |
| 14. | Taxable Income | (875) | (875) | 6,014 | 5,933 | 945 | 935 |
| 15. | Current Income Tax Rate - 39.5% | (345) | (346) | 2,376 | 2,344 | 373 | 369 |
| 16. | Operating Income (line 12 - line 15) | $ (530) | $ (529) | $ 3,638 | $ 3,589 | $ 572 | $ 566 |

(16) Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits.

(17) Adjustment to Test Year operations to reflect the normalization of fossil production maintenance expense and to include the O&M costs of generators acquired for compliance with the Environmental Portfolio Standard.

(18) Adjustment to Test Year operations to reflect the normalization of nuclear production maintenance expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

| Line No. | Description | (19) Annualize Depreciation and Amortization Total Co. (KK) | (19) ACC (LL) | (20) Regulatory Assets Total Co. (MM) | (20) ACC (NN) | (21) ISFSI Asset Total Co. (OO) | (21) ACC (PP) |
|---|---|---|---|---|---|---|---|
| 1. | Electric Operating Revenues | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Purchased Power and Fuel Costs | - | - | - | - | - | - |
| 3. | Oper Rev Less Purch Pwr & Fuel Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 4. | Operations Excluding Fuel Expense | - | - | - | - | - | - |
| 5. | Maintenance | - | - | - | - | - | - |
| 6. | Subtotal | - | - | - | - | - | - |
| 7. | Depreciation and Amortization | 3,027 | 2,373 | (111,754) | (111,760) | 8,251 | 8,130 |
| 8. | Amortization of Gain | - | - | - | - | - | - |
| 9. | Administrative and General | - | - | - | - | - | - |
| 10. | Other Taxes | - | - | - | - | - | - |
| 11. | Total | 3,027 | 2,373 | (111,754) | (111,760) | 8,251 | 8,130 |
| 12. | Operating Income Before Income Tax | (3,027) | (2,373) | 111,754 | 111,760 | (8,251) | (8,130) |
| 13. | Interest Expense | - | - | (1,819) | (1,819) | 76 | 74 |
| 14. | Taxable Income | (3,027) | (2,373) | 113,573 | 113,579 | (8,327) | (8,204) |
| 15. | Current Income Tax Rate - 39.5% | (1,196) | (937) | 44,861 | 44,864 | (3,288) | (3,241) |
| 16. | Operating Income (line 12 - line 15) | $ (1,831) | $ (1,436) | $ 66,893 | $ 66,896 | $ (4,963) | $ (4,889) |

(19) Adjustment to Test Year operations to reflect the requested changes to depreciation rates.

(20) Adjustment to Test Year operations to remove the amortization of regulatory assets which will be fully amortized by June 30, 2004 and to include amortization of continuing regulatory assets.

(21) Adjustment to Test Year operations to reflect the amortization of the System Benefits related ISFSI regulatory asset.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

| Line No. | Description | (22) Reversal of Settlement Write-Off | | (23) Nuclear Decommissioning Funds | | (24) Annualize Property Tax to Year Ending 12-31-2002 | |
|---|---|---|---|---|---|---|---|
| | | Total Co. (QQ) | ACC (RR) | Total Co. (SS) | ACC (TT) | Total Co. (UU) | ACC (VV) |
| 1. | Electric Operating Revenues | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Purchased Power and Fuel Costs | - | - | - | - | - | - |
| 3. | Oper Rev Less Purch Pwr & Fuel Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 4. | Operations Excluding Fuel Expense | - | - | - | - | - | - |
| 5. | Maintenance | - | - | - | - | - | - |
| 6. | Subtotal | - | - | - | - | - | - |
| 7. | Depreciation and Amortization | 15,600 | 15,600 | 7,766 | 7,653 | - | - |
| 8. | Amortization of Gain | - | - | - | - | - | - |
| 9. | Administrative and General | - | - | - | - | - | - |
| 10. | Other Taxes | - | - | - | - | 10,199 | 10,091 |
| 11. | Total | 15,600 | 15,600 | 7,766 | 7,653 | 10,199 | 10,091 |
| 12. | Operating Income Before Income Tax | (15,600) | (15,600) | (7,766) | (7,653) | (10,199) | (10,091) |
| 13. | Interest Expense | 4,094 | 4,094 | - | - | - | - |
| 14. | Taxable Income | (19,694) | (19,694) | (7,766) | (7,653) | (10,199) | (10,091) |
| 15. | Current Income Tax Rate - 39.5% | (7,779) | (7,779) | (3,068) | (3,023) | (4,029) | (3,986) |
| 16. | Operating Income (line 12 - line 15) | $ (7,821) | $ (7,821) | $ (4,698) | $ (4,630) | $ (6,170) | $ (6,105) |

(22) Adjustment to Test Year operations to include a 15-year amortization restoring the $234 million disallowance taken by the Company in consideration of certain benefits previously agreed to under the 1999 Settlement.

(23) Adjustment to Test Year operations to increase contributions to the nuclear decommissioning trust funds.

(24) Adjustment to Test Year operations to reflect property taxes calculated using December 31, 2002 plant balances.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

| Line No. | Description | (25) Financing Application Total Co. (WW) | (25) Financing Application ACC (XX) | (26) Income Tax/Synchronized Interest on Test Year Rate Base Total Co. (YY) | (26) Income Tax/Synchronized Interest on Test Year Rate Base ACC (ZZ) | (27) Miscellaneous Adjustments Total Co. (AAA) | (27) Miscellaneous Adjustments ACC (BBB) |
|---|---|---|---|---|---|---|---|
| 1. | Electric Operating Revenues | $ - | $ - | $ - | $ - | $ 6,117 | $ 6,114 |
| 2. | Purchased Power and Fuel Costs | - | - | - | - | - | - |
| 3. | Oper Rev Less Purch Pwr & Fuel Costs | - | - | - | - | 6,117 | 6,114 |
| | Other Operating Expenses: | | | | | | |
| 4. | Operations Excluding Fuel Expense | - | - | - | - | (699) | (707) |
| 5. | Maintenance | - | - | - | - | - | - |
| 6. | Subtotal | - | - | - | - | (699) | (707) |
| 7. | Depreciation and Amortization | - | - | - | - | - | - |
| 8. | Amortization of Gain | (3,416) | (3,416) | - | - | - | - |
| 9. | Administrative and General | - | - | - | - | - | - |
| 10. | Other Taxes | - | - | - | - | - | - |
| 11. | Total | (3,416) | (3,416) | - | - | (699) | (707) |
| 12. | Operating Income Before Income Tax | 3,416 | 3,416 | - | - | 6,816 | 6,821 |
| 13. | Interest Expense | - | - | (12,783) | (12,363) | - | - |
| 14. | Taxable Income | 3,416 | 3,416 | 12,783 | 12,363 | 6,816 | 6,821 |
| 15. | Current Income Tax Rate - 39.5% | 1,349 | 1,349 | 5,049 | 4,883 | 2,692 | 2,694 |
| 16. | Operating Income (line 12 - line 15) | $ 2,067 | $ 2,067 | $ (5,049) | $ (4,883) | $ 4,124 | $ 4,127 |

(25) Adjustment to Test Year operations to reflect 264 basis point differential specified in Commission Decision No. 65796.

(26) Adjustment to Test Year operations to reflect the synchronization of interest expense using the adjusted year-end 2002 capital structure and cost of long-term debt, as well as the use of the statutory income tax rate.

(27) Adjustment to Test Year operations to eliminate non-recurring and out-of-period expenses.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

(28)

| Line No. | Description | Total Co. (CCC) | ACC (DDD) |
|---|---|---|---|
| | | Total Income Statement Adjustments (a) | |
| 1. | Electric Operating Revenues | $ (115,217) | $ (111,584) |
| 2. | Purchased Power and Fuel Costs | (59,161) | (56,994) |
| 3. | Oper Rev Less Purch Pwr & Fuel Costs | (56,056) | (54,590) |
| | Other Operating Expenses: | | |
| 4. | Operations Excluding Fuel Expense | 100,138 | 80,109 |
| 5. | Maintenance | 17,095 | 17,073 |
| 6. | Subtotal | 117,233 | 97,182 |
| 7. | Depreciation and Amortization | (64,732) | (59,636) |
| 8. | Amortization of Gain | (3,416) | (3,416) |
| 9. | Administrative and General | 2,983 | 3,850 |
| 10. | Other Taxes | 2,219 | 5,992 |
| 11. | Total | 54,287 | 43,972 |
| 12. | Operating Income Before Income Tax | (110,343) | (98,562) |
| 13. | Interest Expense | 6,991 | 10,711 |
| 14. | Taxable Income | (117,334) | (109,273) |
| 15. | Current Income Tax Rate - 39.5% | (46,347) | (43,163) |
| 16. | Operating Income (line 12 - line 15) | $ (63,996) | $ (55,399) |

Recap Schedules:
(a) C-1

C-3

ARIZONA PUBLIC SERVICE COMPANY
Computation of Gross Revenue Conversion Factor
Test Year Ending December 31, 2002

| Line No. | Description | Percentage of Incremental Gross Revenues | Line No. |
|---|---|---|---|
| 1. | Federal Income Taxes | 32.57% | 1. |
| 2. | State Income Taxes | 6.93% | 2. |
| 3. | Total Tax Percentage | 39.50% | 3. |
| 4. | Operating Income % = 100% - Tax Percentage | 60.50% | 4. |
| 5. | 1/Operating Income % = Gross Revenue Conversion Factor | 1.6529 | 5. |

Supporting Schedules:
N/A

Recap Schedules:
A-1

D-1

ARIZONA PUBLIC SERVICE COMPANY
Summary Cost of Capital
(Thousands of Dollars)

| | | End of Test Year 12/31/02 (f) | | | | End of Projected Year 12/31/03 | | | | End of Projected Year 12/31/04 with Proposed Rates | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Invested Capital | Amount | % | Cost Rate (e) | Composite Cost | Amount | % | Cost Rate (e) | Composite Cost | Amount | % | Cost Rate (e) | Composite Cost | Line No. |
| 1. | Long-Term Debt (a) | $2,139,955 | 49.77% | 5.81% | 2.89% | $2,637,848 | 54.95% | 5.76% | 3.17% | $2,630,656 | 49.43% | 5.89% | 2.91% | 1. |
| 2. | Preferred Stock (b) | - | 0.00% | 0.00% | 0.00% | - | 0.00% | 0.00% | 0.00% | - | 0.00% | 0.00% | 0.00% | 2. |
| 3. | Common Equity (c) | 2,159,312 | 50.23% | 11.50% | 5.78% | 2,162,314 | 45.05% | 11.50% | 5.18% | 2,690,969 | 50.57% | 11.50% | 5.82% | 3. |
| 4. | Short-Term Debt (a)(g) | - | 0.00% | 0.00% | 0.00% | - | 0.00% | 0.00% | 0.00% | - | 0.00% | 0.00% | 0.00% | 4. |
| 5. | Deferrals (d) | - | 0.00% | 0.00% | 0.00% | - | 0.00% | 0.00% | 0.00% | - | 0.00% | 0.00% | 0.00% | 5. |
| 6. | Total | $4,299,267 | 100.00% | | 8.67% | $4,800,162 | 100.00% | | 8.35% | $5,321,625 | 100.00% | | 8.73% | 6. |

Supporting Schedules:
(a) D-2
(b) D-3
(c) D-4
(d) E-1

Recap Schedules:
(e) A-3

(f) Adjusted for M&R calls and PC bond rate resets announced through 6/15/03.
(g) Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work In Process, therefore recoverable through AFUDC provisions.

D-2

ARIZONA PUBLIC SERVICE COMPANY
Cost of Long-Term and Short-Term Debt
(Thousands of Dollars)

| Line No. | Description of Debt | End of Test Year 12/31/02 Outstanding | End of Test Year 12/31/02 Annual Interest * | End of Projected Year 12/31/2003 Outstanding | End of Projected Year 12/31/2003 Annual Interest * | End of Projected Year 12/31/2004 with Proposed Rates Outstanding | End of Projected Year 12/31/2004 with Proposed Rates Annual Interest * | Line No. |
|---|---|---|---|---|---|---|---|---|
| | Long-Term: | | | | | | | |
| 1. | First Mortgage Bonds | $259,000 | $15,910 | $259,000 | $15,910 | - | - | 1. |
| 2. | Pollution Control Indebtedness | 386,860 | 8,449 | 386,860 | 10,144 | 565,860 | 22,443 | 2. |
| 3. | Capitalized Lease obligation | 20,400 | 1,180 | 18,293 | 1,058 | 16,101 | 932 | 3. |
| 4. | Other Long-Term Debt - Senior Notes | 173,695 | 10,290 | 173,695 | 10,305 | 173,695 | 10,305 | 4. |
| 5. | Other Long-Term Debt - Unsecured Notes | 1,300,000 | 88,486 | 1,800,000 | 114,518 | 1,875,000 | 121,186 | 5. |
| 6. | Other | - | - | - | - | - | - | 6. |
| 7. | Total Long-Term (a) ** | $2,139,955 (b) | $124,315 | $2,637,848 | $151,935 | $2,630,656 | $154,866 | 7. |
| 8. | Cost Rate (a) | 5.81% | | 5.76% | | 5.89% | | 8. |
| | Short-term: | | | | | | | |
| 9. | Commercial Paper | - | - | - | - | - | - | 9. |
| 10. | Total Short-Term (a) | - *** | - | - *** | - | - *** | - | 10. |
| 11. | Cost Rate (a) | N/A | | N/A | | N/A | | 11. |

* Including amortization of discount, premium and expense.

** Excludes unamortized discount.

***Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work In Process, therefore recoverable through AFUDC provisions.

Supporting Schedules:
(b) E-1 (adjusted for M&R calls and PC bond rate resets announced through 6/15/03).

Recap Schedules:
(a) D-1

D-3

ARIZONA PUBLIC SERVICE COMPANY
Cost of Preferred Stock
(Thousands of Dollars)

| Line No. | Description of Issue | End of Test Year 12/31/02 | | | End of Projected Year 12/31/03 | | | End of Projected Year 12/31/04 with Proposed Rates | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Shares Outstanding | Amount | Dividend Requirement | Shares Outstanding | Amount | Dividend Requirement | Shares Outstanding | Amount | Dividend Requirement | |
| 1. | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 1. |
| 2. | Total (a) (b) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 2. |
| 3. | Cost Rate (a) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 3. |

Supporting Schedules:
(b) E-1

Recap Schedules:
(a) D-1

D-4

ARIZONA PUBLIC SERVICE COMPANY
Cost of Common Equity

A return on average common equity of at least 11.25% to 11.75% is necessary for the Company to attract and maintain investors in its common equity capital. For purposes of this filing, the Company is willing to accept a return on common equity capital in the middle of that range of 11.50%.

Supporting Schedules
N/A

Recap Schedules
D-1

E-1

ARIZONA PUBLIC SERVICE COMPANY
Comparative Balance Sheets
Test Year 12/31/02 and Two Prior Years
(Dollars in Thousands)

| Line No. | Description | Test Year Ended 12/31/2002 | Prior Year Ended 12/31/2001 | Prior Year Ended 12/31/2000 | Line No. |
|---|---|---|---|---|---|
| | UTILITY PLANT: | | | | |
| 1. | Electric plant in service and held for future use | $ 8,299,131 | $ 7,935,206 | $ 7,638,687 | 1. |
| 2. | Less accumulated depreciation and amortization | 3,442,571 | 3,287,333 | 3,115,383 | 2. |
| 3. | Total | 4,856,560 | 4,647,873 | 4,523,304 | 3. |
| 4. | Construction work in progress | 329,089 | 321,305 | 245,749 | 4. |
| 5. | Intangible assets, net of accumulated amortization | 93,259 | 83,135 | 94,393 | 5. |
| 6. | Nuclear fuel, net of amortization | 7,466 | 6,933 | 7,071 | 6. |
| 7. | Utility plant - net (a) | 5,286,374 | 5,059,246 | 4,870,517 | 7. |
| | INVESTMENTS AND OTHER ASSETS : | | | | |
| 8. | Decommissioning trust accounts | 194,440 | 202,036 | 204,716 | 8. |
| 9. | Assets from risk management activities-long term | 31,622 | 2,082 | 32,955 | 9. |
| 10. | Other assets | 19,964 | 76,322 | 45,841 | 10. |
| 11. | Total investments and other assets | 246,026 | 280,440 | 283,512 | 11. |
| | CURRENT ASSETS: | | | | |
| 12. | Cash and cash equivalents | 42,549 | 16,821 | 2,609 | 12. |
| 13. | Accounts receivable: | | | | 13. |
| 14. | Service customers | 136,945 | 182,749 | 422,012 | 14. |
| 15. | Other | 202,597 | 55,016 | 25,089 | 15. |
| 16. | Allowance for doubtful accounts | (1,341) | (3,349) | (2,380) | 16. |
| 17. | Accrued utility revenues | 72,915 | 76,131 | 74,566 | 17. |
| 18. | Materials and supplies, at average cost | 79,985 | 81,215 | 71,966 | 18. |
| 19. | Fossil fuel, at average cost | 28,185 | 27,023 | 19,405 | 19. |
| 20. | Deferred Income tax | 4,094 | - | 5,793 | 20. |
| 21. | Assets from risk management activities | 39,616 | 10,097 | 17,506 | 21. |
| 22. | Other | 45,361 | 42,009 | 38,414 | 22. |
| 23. | Total current assets | 650,906 | 487,712 | 674,980 | 23. |
| | DEFERRED DEBITS: | | | | |
| 24. | Regulatory assets | 241,045 | 342,383 | 469,867 | 24. |
| 25. | Unamortized debt issue costs | 16,696 | 13,163 | 12,805 | 25. |
| 26. | Other | 80,760 | 42,789 | 37,928 | 26. |
| 27. | Total deferred debits | 338,501 | 398,335 | 520,600 | 27. |
| 28. | TOTAL ASSETS | $ 6,521,807 | $ 6,225,733 | $ 6,349,609 | 28. |

Supporting Schedules:
(a) E-5

Recap Schedules:
N/A - See Next Page

ARIZONA PUBLIC SERVICE COMPANY
Comparative Balance Sheets
Test Year 12/31/02 and Two Prior Years
(Dollars in Thousands)

| Line No. | Description | Test Year Ended 12/31/2002 | Year Ended 12/31/2001 | Year Ended 12/31/2000 | Line No. |
|---|---|---|---|---|---|
| | CAPITALIZATION: | | | | |
| 1. | Common stock | $ 178,162 | $ 178,162 | $ 178,162 | 1. |
| 2. | Additional paid-in capital | 1,246,804 | 1,246,804 | 1,246,804 | 2. |
| 3. | Retained earnings | 819,632 | 790,289 | 694,802 | 3. |
| 4. | Accumulated other comprehensive loss: | | | | 4. |
| 5. | Minimum pension liability adjustment | (61,487) | (966) | - | 5. |
| 6. | Derivative instruments | (23,799) | (63,599) | - | 6. |
| 7. | Common stock equity (b) | 2,159,312 | 2,150,690 | 2,119,768 | 7. |
| 8. | Long-term debt less current maturities (b) | 2,217,340 | 1,949,074 | 1,806,908 | 8. |
| 9. | Total capitalization | 4,376,652 | 4,099,764 | 3,926,676 | 9. |
| | CURRENT LIABILITIES: | | | | |
| 10. | Commercial paper | - | 171,162 | 82,100 | 10. |
| 11. | Current maturities of long-term debt (b) | 3,503 | 125,451 | 250,266 | 11. |
| 12. | Accounts payable | 118,133 | 98,959 | 267,999 | 12. |
| 13. | Accrued taxes | 82,557 | 107,595 | 106,515 | 13. |
| 14. | Accrued interest | 42,608 | 41,043 | 39,488 | 14. |
| 15. | Customer deposits | 39,865 | 28,664 | 24,498 | 15. |
| 16. | Deferred income taxes | - | 3,244 | - | 16. |
| 17. | Liabilities from risk management activities | 59,773 | 21,840 | 37,179 | 17. |
| 18. | Other | 51,820 | 18,798 | 81,325 | 18. |
| 19. | Total current liabilities | 398,259 | 616,756 | 889,370 | 19. |
| | DEFERRED CREDITS AND OTHER: | | | | |
| 20. | Deferred income taxes | 1,225,552 | 1,023,079 | 1,110,437 | 20. |
| 21. | Liabilities from risk management activities-long term | 36,678 | 95,159 | 14,711 | 21. |
| 22. | Unamortized gain - sale of utility plant | 59,484 | 64,060 | 68,636 | 22. |
| 23. | Customer advances for construction | 45,513 | 69,293 | 40,694 | 23. |
| 24. | Pension liability | 156,442 | 30,247 | 62,193 | 24. |
| 25. | Other | 223,227 | 227,375 | 236,892 | 25. |
| 26. | Total deferred credits and other | 1,746,896 | 1,509,213 | 1,533,563 | 26. |
| 27. | TOTAL LIABILITIES AND EQUITY | $ 6,521,807 | $ 6,225,733 | $ 6,349,609 | 27. |

Supporting Schedule:
N/A - See Previous Page

Recap Schedules:
(b) A-3

E-2

ARIZONA PUBLIC SERVICE COMPANY
Comparative Income Statements
Test Year Ended 12/31/02 and Two Prior Years
(Dollars in Thousands Except per Share Amounts)

| Line No. | Description | Test Year Ended 12/31/2002 | Prior Year Ended 12/31/2001 | Prior Year Ended 12/31/2000 | Line No. |
|---|---|---|---|---|---|
| | | (a) | (b) | (c) | |
| 1. | Electric Operating Revenues | $ 2,093,393 | $ 3,111,328 | $ 2,934,142 | 1. |
| 2. | Purchased Power and Fuel Costs | 628,030 | 1,541,179 | 1,332,628 | 2. |
| 3. | Operating Revenues Less Fuel Expenses | 1,465,363 | 1,570,149 | 1,601,514 | 3. |
| 4. | Other Operating Expenses: | | | | 4. |
| 5. | Operations and maintenance excluding fuel expenses | 495,845 | 465,561 | 430,092 | 5. |
| 6. | Depreciation and amortization | 399,640 | 420,893 | 425,479 | 6. |
| 7. | Income taxes | 132,953 | 183,640 | 199,977 | 7. |
| 8. | Other taxes | 107,925 | 101,077 | 99,730 | 8. |
| 9. | Total | 1,136,363 | 1,171,171 | 1,155,278 | 9. |
| 10. | Operating Income | 329,000 | 398,978 | 446,236 | 10. |
| 11. | Other Income (Deductions) | | | | 11. |
| 12. | Income taxes | 6,148 | 504 | 4,312 | 12. |
| 13. | Other income | 5,149 | 20,207 | 9,690 | 13. |
| 14. | Other expense | (19,338) | (20,790) | (20,547) | 14. |
| 15. | Total | (8,041) | (79) | (6,545) | 15. |
| 16. | Income Before Interest Deductions | 320,959 | 398,899 | 439,691 | 16. |
| 17. | Interest Deductions | | | | 17. |
| 18. | Interest on long-term debt | 128,462 | 126,118 | 134,431 | 18. |
| 19. | Interest on short-term borrowings | 5,416 | 4,407 | 7,455 | 19. |
| 20. | Debt discount, premium and expense | 2,888 | 2,650 | 2,105 | 20. |
| 21. | Capitalized interest | (15,150) | (14,964) | (10,894) | 21. |
| 22. | Total | 121,616 | 118,211 | 133,097 | 22. |
| 23. | Income Before Accounting Change | 199,343 | 280,688 | 306,594 | 23. |
| 24. | Cumulative effect of change in accounting for derivatives-net on income taxes | - | (15,201) | - | 24. |
| 25. | Net Income | $ 199,343 | $ 265,487 | $ 306,594 | 25. |
| 26. | Preferred Dividends | - | - | - | 26. |
| 27. | Earnings Available for Common Stock | $ 199,343 | $ 265,487 | $ 306,594 | 27. |
| 28. | Average Common Shares Outstanding | 71,264,947 | 71,264,947 | 71,264,947 | 28. |
| 29. | Earnings Per Share of Average Common Stock Outstanding | $ 2.80 | $ 3.73 | $ 4.30 | 29. |

Supporting Schedules:
N/A

Recap Schedules:
A-2

E-3

ARIZONA PUBLIC SERVICE COMPANY
Comparative Statements of Cash Flows
Test Year 12/31/02 and Two Prior Years
(Dollars in Thousands)

| Line No. | Description | Test Year As Of 12/31/2002 | Prior Year As Of 12/31/2001 | Prior Year As Of 12/31/2000 | Line No. |
|---|---|---|---|---|---|
| | Cash Flows from Operating Activities: | | | | |
| 1. | Net income | $ 199,343 | $ 265,487 | $ 306,594 | 1. |
| | Items Not Requiring Cash: | | | | |
| 2. | Depreciation and amortization | 399,640 | 420,893 | 425,479 | 2. |
| 3. | Nuclear fuel amortization | 31,185 | 28,362 | 30,083 | 3. |
| 4. | Deferred income taxes | 206,767 | (26,516) | (65,726) | 4. |
| 5. | Change in mark-to-market | 2,957 | (100,030) | (11,752) | 5. |
| 6. | Cumulative effect of change in accounting-net of income taxes | - | 15,201 | - | 6. |
| | Changes in Certain Current Assets and Liabilities: | | | | |
| 7. | Accounts receivable | (102,450) | 302,283 | (209,705) | 7. |
| 8. | Materials, supplies and fossil fuel | 68 | (16,867) | 475 | 8. |
| 9. | Other current assets | (136) | (5,160) | (26,682) | 9. |
| 10. | Accounts payable | 15,372 | (190,141) | 101,558 | 10. |
| 11. | Accrued taxes | (25,038) | 1,080 | 43,657 | 11. |
| 12. | Accrued interest | 1,565 | 1,555 | 7,189 | 12. |
| 13. | Other current liabilities | 44,224 | (58,361) | 101,685 | 13. |
| 14. | Increase in regulatory assets | (11,029) | (17,516) | (14,138) | 14. |
| 15. | Change in risk management - assets | (22,570) | 10,730 | 13,181 | 15. |
| 16. | Change in customer advances | (23,780) | 28,599 | 2,544 | 16. |
| 17. | Change in pension liability | 5,415 | (30,346) | (18,373) | 17. |
| 18. | Change in other net long-term assets | (18,923) | (14,192) | 64,998 | 18. |
| 19. | Change in other net long-term liabilities | 1,902 | (9,986) | (27,396) | 19. |
| 20. | Net cash flow provided by operating activities | 704,512 | 605,075 | 723,671 | 20. |
| | Cash Flows from Investing Activities: | | | | |
| 21. | Capital expenditures | (490,156) | (465,360) | (464,368) | 21. |
| 22. | Capitalized interest | (15,150) | (14,964) | (10,894) | 22. |
| 23. | Other | 44,918 | (41,926) | (72,189) | 23. |
| 24. | Net cash flow used for investing activities | (460,388) | (522,250) | (547,451) | 24. |
| | Cash Flows from Financing Activities: | | | | |
| 25. | Issuance of long-term debt | 459,926 | 396,072 | 300,000 | 25. |
| 26. | Short-term borrowings | (171,162) | 89,062 | 43,800 | 26. |
| 27. | Dividends paid on common stock | (170,000) | (170,000) | (170,000) | 27. |
| 28. | Repayment and reacquisition of long-term debt | (337,160) | (383,747) | (354,888) | 28. |
| 29. | Net cash flow used for financing activities | (218,396) | (68,613) | (181,088) | 29. |
| 30. | Net increase (decrease) in cash and cash equivalents | 25,728 | 14,212 | (4,868) | 30. |
| 31. | Cash and cash equivalents at beginning of period | 16,821 | 2,609 | 7,477 | 31. |
| 32. | Cash and cash equivalents at end of period | $ 42,549 | $ 16,821 | $ 2,609 | 32. |

E-4

ARIZONA PUBLIC SERVICE COMPANY
Statement of Changes In Stockholders' Equity
Test Year 12/31/02 and Two Prior Years
(Dollars in Thousands)

| Line No. | Description | Preferred Shares | Preferred Stock Amount | Common Shares | Common Stock Amount | Additional Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Loss | Total | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Balance at January 1, 2000 | - | $ - | 71,264,947 | $178,162 | $1,246,804 | $ 558,208 | $ - | $ 1,983,174 | 1 |
| 2 | Net income | | | | | | 306,594 | | 306,594 | 2 |
| 3 | Preferred stock dividends | | - | | | | | | - | 3 |
| 4 | Common stock dividends | | | | | | (170,000) | | (170,000) | 4 |
| 5 | Balance at December 31, 2000 | - | - | 71,264,947 | 178,162 | 1,246,804 | 694,802 | - | 2,119,768 | 5 |
| 6 | Net income | | | | | | 265,487 | | 265,487 | 6 |
| 7 | Minimum pension liability adjustment, net of tax of $634 | | | | | | | (966) | (966) | 7 |
| 8 | Cumulative effect of a change in accounting for derivatives, net of tax of $47,404 | | | | | | | 72,274 | 72,274 | 8 |
| 9 | Unrealized loss on derivative instruments, net of tax of $71,720 | | | | | | | (109,346) | (109,346) | 9 |
| 10 | Reclassification of realized gain to income, net of tax of $17,399 | | | | | | | (26,527) | (26,527) | 10 |
| 11 | Comprehensive Income | | | | | | 265,487 | (64,565) | 200,922 | 11 |
| 12 | Preferred stock dividends | | - | | | | | | - | 12 |
| 13 | Common stock dividends | | | | | | (170,000) | | (170,000) | 13 |
| 14 | Balance at December 31, 2001 | - | - | 71,264,947 | 178,162 | 1,246,804 | 790,289 | (64,565) | 2,150,690 | 14 |
| 15 | Net income | | | | | | 199,343 | | 199,343 | 15 |
| 16 | Minimum pension liability adjustment, net of tax of $39,696 | | | | | | | (60,521) | (60,521) | 16 |
| 17 | Unrealized gain on derivative instruments, net of tax of $25,426 | | | | | | | 38,764 | 38,764 | 17 |
| 18 | Reclassification of realized loss to income, net of tax of $679 | | | | | | | 1,036 | 1,036 | 18 |
| 19 | Comprehensive Income | | | | | | 199,343 | (20,721) | 178,622 | 19 |
| 20 | Preferred stock dividends | | - | | | | | | - | 20 |
| 21 | Common stock dividends | | | | | | (170,000) | | (170,000) | 21 |
| 22 | Balance at December 31, 2002 | - | $ - | 71,264,947 | $178,162 | $1,246,804 | $ 819,632 | $ (85,286) | $ 2,159,312 | 22 |

Supporting Schedules:
N/A

Recap Schedules:
N/A

E-5

ARIZONA PUBLIC SERVICE COMPANY
Detail of Utility Plant
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

| Line No. | Account Description | Account Number | Test Year Ended Bal. 12/31/2002 | Prior Year Ended Bal. 12/31/2001 | Line No. |
|---|---|---|---|---|---|
| | Gross Plant Includible in Rate Base: | | | | |
| 1. | Plant in Service | 101 | $ 8,486,874 | $ 8,094,720 | 1. |
| 2. | Less: Accum. Depreciation-Plant in Service | 108 | 3,421,819 | 3,268,321 | 2. |
| 3. | Accum. Amortization-Plant in Service | 111 | 120,728 | 104,140 | 3. |
| 4. | Net Plant Includible in Rate Base | | 4,944,327 | 4,722,259 | 4. |
| 5. | Nuclear fuel, net of amortization | 120.2-120.5 | 7,466 | 6,933 | 5. |
| 6. | Construction Work in Progress | 107 | 312,852 | 302,633 | 6. |
| 7. | Nuclear Fuel in Process | 120.1 | 16,236 | 18,672 | 7. |
| 8. | Total Construction Work in Progress | | 329,088 | 321,305 | 8. |
| 9. | Plant Held for Future Use | 105 | 5,493 | 10,387 | 9. |
| 10. | Less: Accum Depreciation Related to Plant Held for Future Use | 108 | - | 1,638 | 10. |
| 11. | Net Plant held for Future Use | | 5,493 | 8,749 | 11. |
| 12. | Utility Plant - Net | | $ 5,286,374 | $ 5,059,246 | 12. |

Supporting Schedules:
N/A

Recap Schedules:
E-1
A-4

ARIZONA PUBLIC SERVICE COMPANY
Detail of Plant Includible in Rate Base
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

| Line No. | Account No. | Account Description | Prior Year Ended Bal. 12/31/2001 | Net Additions (12 Months) | Test Year Ended Bal. 12/31/2002 | Line No. |
|---|---|---|---|---|---|---|
| | | Intangible Plant: | | | | |
| 1. | 301 | Organization | $ 74 | - | $ 74 | 1. |
| 2. | 302 | Franchises and Consents | 883 | 1 | 884 | 2. |
| 3. | 303 | Miscellaneous Intangible Plant | 168,943 | 32,607 | 201,550 | 3. |
| 4. | | Total Intangible Plant | $ 169,900 | 32,608 | $ 202,508 | 4. |
| | | Production Plant: | | | | |
| | | Steam Production Plant: | | | | |
| 5. | 310 | Land and Land Rights | 3,294 | 1 | 3,295 | 5. |
| 6. | 311 | Structures and Improvements | 116,250 | (300) | 115,950 | 6. |
| 7. | 312 | Boiler Plant Equipment | 767,931 | 32,527 | 800,458 | 7. |
| 8. | 314 | Turbogenerator Units | 183,786 | 4,417 | 188,203 | 8. |
| 9. | 315 | Accessory Electric Equipment | 135,922 | (899) | 135,023 | 9. |
| 10. | 316 | Miscellaneous Power Plant Equip | 47,909 | 5,433 | 53,342 | 10. |
| 11. | | Total Steam Production Plant | $ 1,255,092 | $ 41,179 | $ 1,296,271 | 11. |
| | | Nuclear Production Plant: | | | | |
| 12. | 320 | Land and Land Rights | 3,400 | - | 3,400 | 12. |
| 13. | 321 | Structures and Improvements | 626,488 | 7,912 | 634,400 | 13. |
| 14. | 322 | Boiler Plant Equipment | 966,970 | (63) | 966,907 | 14. |
| 15. | 323 | Turbogenerator Units | 340,626 | 980 | 341,606 | 15. |
| 16. | 324 | Accessory Electric Equipment | 273,760 | (139) | 273,621 | 16. |
| 17. | 325 | Miscellaneous Power Plant Equip | 131,768 | 688 | 132,456 | 17. |
| 18. | | Total Nuclear Production Plant | $ 2,343,012 | $ 9,378 | $ 2,352,390 | 18. |

Supporting Schedules:
N/A

Recap Schedule:
E-5, page 1 of 6

ARIZONA PUBLIC SERVICE COMPANY
Detail of Plant Includible in Rate Base
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

| Line No. | Account No. | Account Description | Prior Year Ended Bal. 12/31/2001 | Net Additions (12 Months) | Test Year Ended Bal. 12/31/2002 | Line No. |
|---|---|---|---|---|---|---|
| | | Hydraulic Production Plant: | | | | |
| 1. | 330 | Land and Land Rights | $ 65 | - | $ 65 | 1. |
| 2. | 331 | Structures and Improvements | 101 | - | 101 | 2. |
| 3. | 332 | Reservoirs, Dams and Waterways | 992 | - | 992 | 3. |
| 4. | 333 | Water Wheels, Turbines and Generators | 157 | - | 157 | 4. |
| 5. | 334 | Accessory Electric Equipment | 628 | - | 628 | 5. |
| 6. | 335 | Miscellaneous Power Plant Equip | 126 | - | 126 | 6. |
| 7. | 336 | Roads, Railroads and Bridges | 77 | - | 77 | 7. |
| 8. | | Total Hydraulic Production Plant | $ 2,146 | - | $ 2,146 | 8. |
| | | Other Production Plant: | | | | |
| 9. | 340 | Land and Land Rights | 28 | - | 28 | 9. |
| 10. | 341 | Structures and Improvements | 6,513 | 3,155 | 9,668 | 10. |
| 11. | 342 | Fuel Holders, Producers and Accessories | 23,760 | 2,416 | 26,176 | 11. |
| 12. | 343 | Prime Movers | 32,455 | 329 | 32,784 | 12. |
| 13. | 344 | Generators | 105,476 | 3,851 | 109,327 | 13. |
| 14. | 345 | Accessory Electric Equipment | 15,273 | 4,110 | 19,383 | 14. |
| 15. | 346 | Miscellaneous Power Plant Equip | 5,141 | 237 | 5,378 | 15. |
| 16. | | Total Other Production Plant | $ 188,646 | 14,098 | $ 202,744 | 16. |
| 17. | | Total Production Plant | $ 3,788,896 | $ 64,655 | $ 3,853,551 | 17. |

Supporting Schedules:
N/A

Recap Schedule:
E-5, page 1 of 6

ARIZONA PUBLIC SERVICE COMPANY
Detail of Plant Includible in Rate Base
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

| Line No. | Account No. | | Account Description | Prior Year Ended Bal. 12/31/2001 | Net Additions (12 Months) | Test Year Ended Bal. 12/31/2002 | Line No. |
|---|---|---|---|---|---|---|---|
| | | | Transmission Plant | | | | |
| 1. | 350 | (a) | Land and Land Rights | $ 48,606 | $ (160) | $ 48,446 | 1. |
| 2. | 352 | (a) | Structures and Improvements | 30,336 | (2,718) | 27,618 | 2. |
| 3. | 353 | (a) | Station Equipment | 383,887 | 43,134 | 427,021 | 3. |
| 4. | 354 | (a) | Towers and Fixtures | 83,289 | 176 | 83,465 | 4. |
| 5. | 355 | (a) | Poles and Fixtures | 165,072 | 9,123 | 174,195 | 5. |
| 6. | 356 | (a) | Overhead Conductors and Devices | 186,973 | 18,798 | 205,771 | 6. |
| 7. | 357 | | Underground Conduit | 9,401 | 1,043 | 10,444 | 7. |
| 8. | 358 | | Underground Conductors and Devices | 16,526 | 2,025 | 18,551 | 8. |
| 9. | | | Total Transmission Plant | $ 924,090 | $ 71,421 | $ 995,511 | 9. |
| | | | Distribution Plant: | | | | |
| 10. | 360 | | Land and Land Rights | 22,083 | 4,672 | 26,755 | 10. |
| 11. | 361 | | Structures and Improvements | 24,888 | 1,123 | 26,011 | 11. |
| 12. | 362 | | Station Equipment | 194,232 | 18,125 | 212,357 | 12. |
| 13. | 364 | | Poles, Towers, and Fixtures | 322,305 | 15,815 | 338,120 | 13. |
| 14. | 365 | | Overhead Conductors and Devices | 212,086 | 6,771 | 218,857 | 14. |
| 15. | 366 | | Underground Conduit | 385,609 | 40,114 | 425,723 | 15. |
| 16. | 367 | | Underground Conductors and Devices | 754,929 | 50,576 | 805,505 | 16. |
| 17. | 368 | | Line Transformers | 466,808 | 20,209 | 487,017 | 17. |
| 18. | 369 | | Services | 230,739 | 11,666 | 242,405 | 18. |
| 19. | 370 | | Meters | 144,577 | 1,445 | 146,022 | 19. |
| 20. | 371 | | Installations on Customers' Premises | 23,469 | 1,926 | 25,395 | 20. |
| 21. | 373 | | Street Lighting and Signal Systems | 57,023 | 164 | 57,187 | 21. |
| 22. | | | Total Distribution Plant | $ 2,838,748 | $ 172,606 | $ 3,011,354 | 22. |

(a) Excludes SCE 500kv Transmission Line

Supporting Schedules:
N/A

Recap Schedule:
E-5, page 1 of 6

ARIZONA PUBLIC SERVICE COMPANY
Detail of Plant Includible in Rate Base
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

| Line No. | Account No. | | Account Description | Prior Year Ended Bal. 12/31/2001 | Net Additions (12 Months) | Test Year Ended Bal. 12/31/2002 | Line No. |
|---|---|---|---|---|---|---|---|
| | | | General Plant | | | | |
| 1. | 389 | | Land and Land Rights | $ 6,717 | $ 610 | $ 7,327 | 1. |
| 2. | 390 | | Structures and Improvements | 89,760 | 18,068 | 107,828 | 2. |
| 3. | 391 | (b) | Office Furniture and Equipment | 60,057 | 12,111 | 72,168 | 3. |
| 4. | 392 | (b) | Transportation Equipment | 31,273 | 16,692 | 47,965 | 4. |
| 5. | 393 | | Stores Equipment | 1,275 | (48) | 1,227 | 5. |
| 6. | 394 | | Tools, Shop and Garage Equipment | 10,840 | 1,833 | 12,673 | 6. |
| 7. | 395 | | Laboratory Equipment | 1,351 | - | 1,351 | 7. |
| 8. | 396 | | Power Operated Equipment | 34,849 | (6,901) | 27,948 | 8. |
| 9. | 397 | (a) | Communication Equipment | 84,078 | 8,220 | 92,298 | 9. |
| 10. | 398 | | Miscellaneous Equipment | 1,083 | 253 | 1,336 | 10. |
| 11. | | | Total General Plant | $ 321,283 | $ 50,838 | $ 372,121 | 11. |
| | | | SCE 500kv Transmission Line | | | | |
| 12. | 350 | | Land and Land Rights | 2,362 | - | 2,362 | 12. |
| 13. | 352 | | Structures and Improvements | 410 | - | 410 | 13. |
| 14. | 353 | | Station Equipment | 9,437 | 26 | 9,463 | 14. |
| 15. | 354 | | Towers and Fixtures | 13,753 | - | 13,753 | 15. |
| 16. | 355 | | Poles and Fixtures | 930 | - | 930 | 16. |
| 17. | 356 | | Overhead Conductors and Devices | 22,654 | - | 22,654 | 17. |
| 18. | | | Total SCE Transmission Line | $ 49,546 | $ 26 | $ 49,572 | 18. |

(a) Excludes SCE 500kv Transmission Line
(b) Includes Capitalized Leases

Supporting Schedules:
N/A

Recap Schedule:
E-5, page 1 of 6

ARIZONA PUBLIC SERVICE COMPANY
Detail of Plant Includible in Rate Base
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

| Line No. | Account No. | Account Description | Prior Year Ended Bal. 12/31/2001 | Net Additions (12 Months) | Test Year Ended Bal. 12/31/2002 | Line No. |
|---|---|---|---|---|---|---|
| 1. | 397 | SCE 500kv - General Plant Communication Equipment | $ 2,257 | - | $ 2,257 | 1. |
| 2. | | Total SCE 500kv Line | $ 51,803 | $ 26 | $ 51,829 | 2. |
| 3. | | Total Plant in Service - 101 | $ 8,094,720 | $ 392,154 | $ 8,486,874 | 3. |
| 4. | | Total Net Plant Includible in Rate Base | $ 8,094,720 | $ 392,154 | $ 8,486,874 | 4. |

Supporting Schedules:
N/A

Recap Schedule:
E-5, page 1 of 6

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ARIZONA PUBLIC SERVICE COMPANY
Electric Operating Statistics
Test Year and Two Prior Years

| Line No. | Description | Test Year Ended 12/31/02 | Prior Year Ended 12/31/01 | Prior Year Ended 12/31/00 | Line No. |
|---|---|---|---|---|---|
| | **kWh Sales (thousands)** | | | | |
| 1. | Residential | 10,447,596 | 10,320,732 | 9,768,654 | 1. |
| 2. | Commercial | 10,594,216 | 10,479,999 | 10,044,996 | 2. |
| 3. | Industrial | 2,195,881 | 2,433,122 | 2,510,839 | 3. |
| 4. | Irrigation | 30,994 | 28,667 | 86,997 | 4. |
| 5. | Public Street and Highway Lighting | 99,529 | 94,693 | 92,915 | 5. |
| 6. | Other Sales to Public Authorities | 4,474 | 4,933 | 4,730 | 6. |
| 7. | Total Sales to Ultimate Consumers | 23,372,690 | 23,362,146 | 22,509,131 | 7. |
| 8. | Sales for Resale - Requirements Customers | 493,090 | 1,483,509 | 1,045,944 | 8. |
| 9. | Sales for Resale - Other Customers | 5,206,324 | 6,965,009 | 10,881,910 | 9. |
| 10. | Total Sales for Resale | 5,699,414 | 8,448,518 | 11,927,854 | 10. |
| 11. | **Total kWh Sales** | 29,072,104 | 31,810,664 | 34,436,985 | 11. |
| | **Average Number of Customers** | | | | |
| 12. | Residential | 801,801 | 776,339 | 749,285 | 10. |
| 13. | Commercial | 95,575 | 93,499 | 89,539 | 11. |
| 14. | Industrial | 3,325 | 3,320 | 3,243 | 12. |
| 13. | Irrigation | 346 | 366 | 412 | 13. |
| 14. | Public Street and Highway Lighting | 759 | 780 | 717 | 14. |
| 15. | Other Sales to Public Authorities | 223 | 233 | 217 | 15. |
| 16. | Total Retail Consumers | 902,029 | 874,537 | 843,413 | 16. |
| 17. | Sales for Resale - Requirements Customers | 16 | 18 | 16 | 17. |
| 18. | **Total Customers** | 902,045 | 874,555 | 843,429 | 18. |
| | **Average kWh Use (Annual)** | | | | |
| 19. | Residential | 13,030 | 13,294 | 13,037 | 19. |
| 20. | Commercial | 110,847 | 112,087 | 112,186 | 20. |
| 21. | Industrial | 660,415 | 732,868 | 774,233 | 21. |
| 22. | Irrigation | 89,578 | 78,325 | 211,158 | 22. |
| 23. | Public Street and Highway Lighting | 131,132 | 121,401 | 129,589 | 23. |
| 24. | Other Sales to Public Authorities | 20,063 | 21,172 | 21,797 | 24. |
| 25. | Sales for Resale - Requirements Customers | 30,818,125 | 82,417,167 | 65,371,500 | 25. |
| | **Average Annual Revenue per Residential Customer** | | | | |
| 26. | Annual Revenue | 1,139.97 | 1,176.85 | 1,174.55 | 26. |
| 27. | Revenue per kWh (Cents) | 8.75 | 8.85 | 9.01 | 27. |
| 28. | **Direct kWh Production Expense per kWh Sold (Cents)** | 2.90 | 5.49 | 4.09 | 28. |
| 29. | **Direct kWh Transmission Expense per kWh Sold (Cents)** | 0.09 | 0.08 | 0.07 | 29. |

Supporting Schedules:
N/A

Recap Schedules:
N/A

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ARIZONA PUBLIC SERVICE COMPANY
Taxes Charged to Operations
Test Year 12/31/02 and Prior Two Years
(Dollars in Thousands)

| Line No. | Discription | Test Year Ended 12/31/2002 (a) | Prior Year Ended 12/31/2001 (b) | Prior Year Ended 12/31/2000 (c) | Line No. |
|---|---|---|---|---|---|
| | Federal Taxes: | | | | |
| 1. | Income | $ (56,554) | $ 139,867 | $ 188,914 | 1. |
| 2. | F.I.C.A.* | 29,831 | 27,967 | 27,249 | 2. |
| 3. | Deferred Income Taxes | 170,143 | (22,221) | (28,494) | 3. |
| 4. | Environmental | - | - | - | 4. |
| 5. | Unemployment | 316 | 323 | 348 | 5. |
| 6. | Miscellaneous | - | - | - | 6. |
| 7. | Total | 143,736 | 145,936 | 188,017 | 7. |
| | State Taxes: | | | | |
| 8. | Ad Valorem** | 103,906 | 99,489 | 99,017 | 8. |
| 9. | Sales*** | 130,981 | 125,143 | 113,889 | 9. |
| 10. | Income | (16,825) | 26,504 | 34,932 | 10. |
| 11. | Unemployment | 34 | 486 | 164 | 11. |
| 12. | Deferred Income Taxes | 36,191 | (4,632) | (6,111) | 12. |
| 13. | Total | 254,287 | 246,990 | 241,891 | 13. |
| | Local Taxes: | | | | |
| 14. | Sales | - | - | - | 14. |
| 15. | Total Taxes | $ 398,023 | $ 392,926 | $ 429,908 | 15. |

* Includes payroll related taxes charged to others
** Includes local taxes
*** For SEC reporting purposes, sales taxes related to sales of electricity are excluded from both revenues and other taxes.

Supporting Schedules:
N/A

Recap Schedules:
N/A

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ARIZONA PUBLIC SERVICE COMPANY
Notes to Financial Statements

See the attached Arizona Public Service Company Form 10-K filed with the Securities and Exchange Commission for the fiscal year ended December 31, 2002. The notes to the financial statements are contained on pages 62 through 109 of the document.

| Supporting Schedules | Recap Schedules |
| --- | --- |
| N/A | N/A |

# SECURITIES AND EXCHANGE COMMISSION

**WASHINGTON, D.C. 20549**

# FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the fiscal year ended December 31, 2002**

**OR**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the transition period from _____ to _____**
**Commission File Number 1-4473**

# Arizona Public Service Company

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| ARIZONA<br>(State or other jurisdiction<br>of incorporation or organization) | 86-0011170<br>(I.R.S. Employer Identification No.) |
| 400 North Fifth Street, P.O. Box 53999<br>Phoenix, Arizona 85072-3999<br>(Address of principal executive offices,<br>including zip code) | (602) 250-1000<br>(Registrant's telephone number,<br>including area code) |

**Securities registered pursuant to Section 12(b) or 12(g) of the Act:** None.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in any amendment to this Form 10-K. [ X ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).
Yes __ No X

As of March 31, 2003, there were issued and outstanding 71,264,947 shares of the registrant's common stock, $2.50 par value, all of which were held beneficially and of record by Pinnacle West Capital Corporation.

**The registrant meets the conditions set forth in General Instruction I1(a) and (b) and is therefore filing this document with the reduced disclosure format.**

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## GLOSSARY

ACC – Arizona Corporation Commission

ACC Staff – Staff of the Arizona Corporation Commission

ADEQ – Arizona Department of Environmental Quality

AISA – Arizona Independent Scheduling Administrator

ALJ – Administrative Law Judge

ANPP – Arizona Nuclear Power Project, also known as Palo Verde

APS – Arizona Public Service Company, the Company

APS Energy Services – APS Energy Services Company, Inc., a subsidiary of Pinnacle West

CC&N – Certificate of Convenience and Necessity

Cholla – Cholla Power Plant

Citizens – Citizens Communications Company

Clean Air Act – the Clean Air Act, as amended

Company – Arizona Public Service Company

CPUC – California Public Utility Commission

DOE – United States Department of Energy

EITF – the FASB's Emerging Issues Task Force

EPA – United States Environmental Protection Agency

ERMC –Energy Risk Management Committee

FASB – Financial Accounting Standards Board

FERC – United States Federal Energy Regulatory Commission

FIN – FASB Interpretation

Financing Application – our application filed with the ACC on September 16, 2002

FIP – Federal Implementation Plan

Fitch – Fitch, Inc.

Four Corners – Four Corners Power Plant

GAAP – accounting principles generally accepted in the United States of America

Interim Financing Application – our application filed with the ACC on November 8, 2002

IRS – United States Internal Revenue Service

ISO – California Independent System Operator

kW – kilowatt, one thousand watts

kWh – kilowatt – hour, one thousand watts per hour

Moody's – Moody's Investors Service

MW – megawatt, one million watts

MWh – megawatt-hours, one million watts per hour

Native Load – retail and wholesale sales supplied under traditional cost-based rate regulation

1999 Settlement Agreement – comprehensive settlement agreement related to the implementation of retail electric competition

NOV – Notice of Violation

NRC – United States Nuclear Regulatory Commission

Nuclear Waste Act – Nuclear Waste Policy Act of 1982, as amended

OCI – other comprehensive income

Palo Verde – Palo Verde Nuclear Generating Station

PG&E – PG&E Corp.

Pinnacle West – Pinnacle West Capital Corporation, parent company of the Company

Pinnacle West Energy – Pinnacle West Energy Corporation, a subsidiary of Pinnacle West

PRP – potentially responsible parties under Superfund

PX – California Power Exchange

RTO – regional transmission organization

Rules – ACC retail electric competition rules

Salt River Project – Salt River Project Agricultural Improvement and Power District

SCE – Southern California Edison Company

SEC – United States Securities and Exchange Commission

SFAS – Statement of Financial Accounting Standards

SMD – standard market design

SPE – special-purpose entity

Standard & Poor's – Standard & Poor's Corporation

SunCor – SunCor Development Company, a subsidiary of Pinnacle West

Superfund – Comprehensive Environmental Response, Compensation and Liability Act

System – non-trading energy related activities

T&D – transmission and distribution

Track A Order – ACC order dated September 10, 2002 regarding generation asset transfers and related issues

Track B Order –ACC order dated March 14, 2003 regarding competitive solicitation requirements for power purchases by Arizona's investor-owned electric utilities

Trading – energy-related activities entered into with the objective of generating profits on changes in market prices

VIE – variable interest entity

WestConnect – WestConnect RTO, LLC, a proposed RTO to be formed by owners of electric transmission lines in the southwestern United States

## PART I

## ITEM 1. BUSINESS

## CURRENT STATUS

### General

We were incorporated in 1920 under the laws of Arizona and currently have more than 902,000 customers. Pinnacle West owns all of our outstanding common stock. We provide either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about half of the Phoenix metropolitan area. Electricity is delivered through a distribution system that we own. We also generate, sell and deliver electricity to wholesale customers in the western United States. Our marketing and trading division, as discussed below, sells, in the wholesale market, our and Pinnacle West Energy's generation output that is not needed for our Native Load, which includes loads for retail customers and cost-of-service wholesale customers. We do not distribute any products. During 2002, no single purchaser or user of energy (other than Pinnacle West) accounted for more than 1% of total electric revenues.

At December 31, 2002, we employed approximately 5,100 people, which includes employees assigned to joint-owned generating facilities for which we serve as the generating facility manager. Our principal executive offices are located at 400 North Fifth Street, Phoenix, Arizona 85004 (telephone 602-250-1000).

### Marketing and Trading

In early 2003, the marketing and trading division was moved from Pinnacle West to us for future marketing and trading activities (existing wholesale contracts will remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of our generating assets to Pinnacle West Energy (see "Overview of Arizona Regulatory Developments" below). The marketing and trading division sells, in the wholesale market, our and Pinnacle West Energy generation output that is not needed for our Native Load, which includes loads for retail customers and traditional cost-of-service wholesale customers. The division focuses primarily on managing our purchased power and fuel risks in connection with our costs of serving retail customer energy requirements. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Factors Affecting Our Financial Outlook" in Item 7 for a discussion of our implementation of an ACC-mandated process by which we must competitively procure energy. Additionally, the marketing and trading division, subject to specific parameters, markets, hedges and trades in electricity, fuels and emission allowances and credits. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 for information about the historical and prospective contribution of the marketing and trading activities to our financial results.

### Business Segments

We have two principal business segments (determined by services and the regulatory environment):

- our regulated electricity segment (98% of operating revenues in 2002), which consists of regulated traditional retail and wholesale electricity businesses and related activities, and includes electricity transmission, distribution and generation; and

- our marketing and trading segment (2% of operating revenues in 2002), which consists of our competitive energy business activities, including wholesale marketing and trading.

See Note 15 of Notes to Financial Statements in Item 8 for financial information about our business segments.

**Overview of Arizona Regulatory Developments**

As discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Factors Affecting Our Financial Outlook" in Item 7, we believe pending Arizona regulatory matters are among the key factors affecting our financial outlook.

**General**

On September 21, 1999, the ACC approved Rules that provided a framework for the introduction of retail electric competition in Arizona. On September 23, 1999, the ACC approved a comprehensive settlement agreement among us and various parties related to the implementation of retail electric competition in Arizona. Under the Rules, as modified by the 1999 Settlement Agreement, we were required to transfer all of our competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates no later than December 31, 2002. Consistent with that requirement, we had been addressing the legal and regulatory requirements necessary to complete the transfer of our generation assets to Pinnacle West Energy on or before that date. On September 10, 2002, the ACC issued the Track A Order, which, among other things, directed us not to transfer our generation assets to Pinnacle West Energy. See Note 3 of Notes to Financial Statements in Item 8 for additional information about the 1999 Settlement Agreement, the Rules (including legal challenges to the Rules), and the Track A Order.

**Financing Application**

On September 16, 2002, we filed an application with the ACC requesting the ACC to allow us to borrow up to $500 million and to lend the proceeds to Pinnacle West Energy or to Pinnacle West; to guarantee up to $500 million of Pinnacle West Energy's or Pinnacle West's debt; or a combination of both, not to exceed $500 million in the aggregate. In our application, we stated that the ACC's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between us and Pinnacle West Energy under different regulatory regimes result in Pinnacle West Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing that Pinnacle West provided to fund the construction of Pinnacle West Energy generation assets or from effectively competing in wholesale markets. On March 27, 2003, the ACC authorized us to lend up to $500 million to Pinnacle West Energy, guarantee up to $500 million of Pinnacle West Energy debt or a combination of both, not to exceed $500 million in the aggregate. See "ACC Applications" in Note 3 of Notes to Financial Statements in Item 8 for additional information.

### Competitive Procurement Process

On September 10, 2002, the ACC issued an order that, among other things, established a requirement that we competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order, which documented the decision made by the ACC at its open meeting on February 27, 2003, addressing this requirement. Under the order, we will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, we will be required to solicit competitive bids for about 2,500 MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of our total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in our retail load and retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets." The order recognizes our right to reject any bids that are unreasonable, uneconomical or unreliable.

We expect to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply our electricity requirements. See "Track B Order" in Note 3 of Notes to Financial Statements in Item 8 for additional information.

### General Rate Case

As required by the 1999 Settlement Agreement, on or before June 30, 2003, we will file a general rate case with the ACC. In this rate case, we will update our cost of service and rate design. In addition, we expect to seek:

- rate base treatment of certain power plants currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3);
- recovery of the $234 million pretax asset write-off recorded by us as a result of the 1999 Settlement Agreement; and
- recovery of costs incurred by us in preparation for the previously required transfer of generation assets to Pinnacle West Energy.

We assume that the ACC will make a decision in this general rate case by the end of 2004.

## Forward-Looking Statements

This document contains forward-looking statements based on current expectations and we assume no obligation to update these statements or make any further statements on any of these issues, except as required by applicable law. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including price

caps and other market constraints imposed by the FERC; regional economic and market conditions, including the California energy situation and completion of generation and transmission construction in the region, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital and access to capital markets; weather variations affecting local and regional customer energy usage; the effect of conservation programs on energy usage; power plant performance; our ability to compete successfully outside traditional regulated markets (including the wholesale market); our ability to manage our marketing and trading activities and the use of derivative contracts in our business; technological developments in the electric industry; the performance of the stock market, which affects the amount of our required contributions to our pension plan and nuclear decommissioning trust funds; and other uncertainties, all of which are difficult to predict and many of which are beyond our control.

## REGULATION AND COMPETITION

### Retail

The ACC regulates our retail electric rates and our issuance of securities. The ACC must also approve any transfer of our utility property and certain transactions between us and affiliated parties. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Our Financial Outlook" in Item 7 and Note 3 of Notes to Financial Statements in Item 8 for a discussion of the status of electric industry restructuring in Arizona.

We are subject to varying degrees of competition from other utilities in Arizona (such as Tucson Electric Power Company, Southwest Gas Corporation and Citizens Communications Company) as well as cooperatives, municipalities, electrical districts and similar types of governmental organizations (principally Salt River Project). We also face competition from low-cost hydroelectric power and parties that have access to low-priced preferential federal power and other subsidies. In addition, some customers, particularly industrial and large commercial customers, may own and operate facilities to generate their own electric energy requirements. Although some very limited retail competition existed in our service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to our customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter our service territory. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a restructured industry.

### Wholesale

#### General

The FERC regulates rates for wholesale power sales and transmission services. During 2002, approximately 11% of our electric operating revenues resulted from such sales and services. In early 2003, the marketing and trading division was moved from Pinnacle West to us for all future marketing and trading activities (existing wholesale contracts will remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of our generating assets to Pinnacle West Energy (see "Overview of Arizona Regulatory Developments" above). The marketing and trading division sells, in the wholesale market, our and Pinnacle West Energy's generation output that is not needed for our Native Load and, in doing so, competes with other utilities, power marketers and independent power producers. The division focuses primarily on managing our purchased power and fuel risks in connection with our costs of serving retail customer

energy requirements. See "Track B Order" in Note 3 of Notes to Financial Statements in Item 8 for information regarding an ACC-mandated process by which we must competitively procure energy.

**Regional Transmission Organizations**

On December 20, 1999, the FERC issued its Order No. 2000 regarding regional transmission organizations. In its order, the FERC set minimum characteristics and functions that must be met by utilities that participate in RTOs. The characteristics for an acceptable RTO include independence from market participants, operational control over a region large enough to support efficient and nondiscriminatory markets and exclusive authority to maintain short-term reliability.

As stated in Order No. 2000, the FERC believes that a number of benefits will result from the formation of RTOs throughout the country, and it has moved aggressively to ensure that all public utilities participate in an RTO or demonstrate why such participation is not feasible. According to the FERC, the benefits it expects to result from RTO formation include: (1) improvements in transmission system operations with resulting enhancements to inter-regional trade, congestion management, reliability and coordination; and (2) improved performance of energy markets, including greater incentives for efficient generator performance and enhanced potential for demand response.

On October 16, 2001, we and other owners of electric transmission lines in the Southwest filed with the FERC a request for a declaratory order confirming that their proposal to form WestConnect RTO, LLC would satisfy the FERC's requirements for the formation of an RTO. We and the other filing parties have agreed to fund the start-up of WestConnect's operations, which are subject to FERC approval. WestConnect has been structured as a for-profit RTO and evolved from DesertSTAR, a not-for-profit corporation in which we participated, which was originally designed to serve as an RTO for the southwestern United States. The success of WestConnect will be largely dependent on participation by all major transmission owners in the Southwest. The success is also dependent on support from the affected state regulatory commissions.

On October 10, 2002, the FERC issued an order finding that the WestConnect proposal, if modified to address specified issues, could meet the FERC's RTO requirements and provide the basic framework for a standard market design for the Southwest. In its order, the FERC also stated that its approval of various WestConnect provisions addressed in the order would not be overturned or affected by the final rule the FERC intends to ultimately adopt in response to its July 31, 2002 Notice of Proposed Rulemaking regarding a standard market design for the electric utility industry (see "Federal" in Note 3 of Notes to Financial Statements in Item 8 for additional information regarding the Notice of Proposed Rulemaking). On November 12, 2002, we and other owners filed a request for rehearing and clarification on portions of the October 10, 2002 order.

On December 23, 2002, the FERC issued its order on rehearing. In it, the FERC clarified the RTO elements that it had approved. In its order, the FERC stated that it envisions the Seams Steering Group - Western Interconnection (SSG-WI) as the entity that will facilitate a common market design for the West. The SSG-WI consists of western transmission owners, including members of WestConnect. The FERC also noted that its prior WestConnect order did not address other elements of market design that are currently being considered in the pending SMD proposal and/or through the SSG-WI process. The FERC clarified that there are only three areas that would be subject to the final SMD rule: (1) transmission credits; (2) resource adequacy; and (3) market monitoring.

The order also stated that FERC's approval of the for-profit structure will not predetermine its decision in the final SMD rule regarding whether a for-profit independent transmission company should be permitted to perform all the functions of an independent transmission provider. To the extent that the FERC has not addressed aspects of WestConnect's for-profit proposal or WestConnect's proposed particular functions, such elements will be subject to review for consistency with Order No. 2000 and other related decisions regarding functions that may be performed by an independent transmission company. The WestConnect applicants sought further clarification of that aspect of the rehearing order. The FERC has indicated that it will issue an order on the WestConnect applicants' motion for clarification before April 14, 2003.

The ACC Rules also required the formation and implementation of an Arizona Independent Scheduling Administrator. The purpose of the AISA is to oversee the application of operating protocols to ensure statewide consistency for transmission access. The AISA is anticipated to be a temporary organization until the implementation of an independent system operator or RTO. APS participated in the creation of the AISA, a not-for-profit entity, and the filing at the FERC for approval of its operating protocols. The operating protocols were partially rejected and the remainder are currently under review. On February 8, 2002, the ACC's Chief ALJ issued a procedural order which consolidated the ACC docket relating to the AISA with several other pending ACC dockets. In its Track B Order, the ACC directed that a hearing be held on whether or not we should be required to continue funding the AISA.

**Purchased Power and Generating Fuel**

See "Properties – Net Accredited Capacity" in Item 2 for information about our power plants by fuel types.

**2002 Energy Mix**

Our sources of energy during 2002 were: purchased power – 30.4% (approximately 60% of which was for wholesale power operations); coal – 37.2%; nuclear –27.7%; gas – 4.6%; and other (includes oil, hydro and solar) – 0.1%.

**Coal Supply**

**Cholla** Cholla is a coal-fired power plant located in northeastern Arizona. It is a jointly-owned facility operated by us. We purchase most of Cholla's coal requirements from a coal supplier that mines all of the coal under a long-term lease of coal reserves owned by the Navajo Nation, the federal government and private landholders. Cholla has sufficient coal, including low sulfur coal, under current contracts to ensure a reliable fuel supply through 2007. We purchase a portion of Cholla's coal requirements on the spot market to take advantage of competitive pricing options. Following expiration of current contracts, we believe that numerous competitive fuel supply options will exist to ensure the continued operation of Cholla for its useful life.

**Four Corners** Four Corners is a coal-fired power plant located in the northwest corner of New Mexico. It is a jointly-owned facility operated by us. We purchase all of Four Corners' coal requirements from a supplier with a long-term lease of coal reserves owned by the Navajo Nation. Four Corners is under contract for coal through 2004, with options to extend the contract through the plant site lease expiration in 2017.

**Navajo Generating Station** The Navajo Generating Station is a coal-fired power plant located in northern Arizona. It is a jointly-owned facility operated by Salt River Project. The Navajo Generating Station's coal requirements are purchased from a supplier with long-term leases from the Navajo Nation and the Hopi Tribe. The Navajo Generating Station is under contract with its coal supplier through 2011, with options to extend through the plant site lease expiration in 2019. The Navajo Generating Station lease waives certain taxes through the lease expiration in 2019. The lease provides for the potential to renegotiate the coal royalty in 2007 and 2017, which may impact the fuel price.

See "Properties – Net Accredited Capacity" in Item 2 for information about our ownership interest in Cholla, Four Corners and the Navajo Generating Station. See Note 10 of Notes to Financial Statements in Item 8 for information regarding our coal mine reclamation obligations.

**Natural Gas Supply**

We purchase the majority of our natural gas requirements for our gas-fired plants under contracts with a number of natural gas suppliers. Our natural gas supply is transported pursuant to a firm, full requirements transportation service agreement with El Paso Natural Gas Company. The transportation agreement features a 10-year rate moratorium established in a comprehensive rate case settlement entered into in 1996.

In a pending FERC proceeding, El Paso Natural Gas Company has proposed allocating its gas pipeline capacity in such a way that our (and other companies with the same contract type) gas transportation rights could be significantly impacted. Various parties, including Pinnacle West Energy and us, have challenged this allocation as being inconsistent with El Paso Natural Gas Company's existing contractual obligations and a 1996 settlement. On May 31, 2002 the FERC issued an order requiring the conversion of all firm, full requirements contracts to contract demand contracts by November 1, 2002. In addition, the FERC order set forth procedures to encourage parties to resolve the details of such conversions through a settlement process. We and other full requirements contract holders sought rehearing of the FERC order and requested a stay of the November 1, 2002 implementation date. On September 20, 2002, the FERC issued another order clarifying the capacity allocation methodology, extending the conversion implementation date from November 1, 2002 to May 1, 2003 and approving the reallocation of costs for the transportation service. We and other full requirements contract holders have sought rehearings of this FERC order. The FERC has indicated that it intends to issue an order on the merits in this proceeding by April 14, 2003. Although we cannot predict the outcome of this matter, we currently do not expect this matter to have a material adverse impact on our financial position, results of operations or liquidity. We are continuing to analyze the market to determine the most favorable source and method of meeting our natural gas requirements.

**Nuclear Fuel Supply**

**Palo Verde Fuel Cycle** Palo Verde is a nuclear power plant located about 50 miles west of Phoenix, Arizona. It is a jointly-owned facility operated by us. The fuel cycle for Palo Verde is comprised of the following stages:

- mining and milling of uranium ore to produce uranium concentrates;
- conversion of uranium concentrates to uranium hexafluoride;
- enrichment of uranium hexafluoride;
- fabrication of fuel assemblies;
- utilization of fuel assemblies in reactors; and
- storage and disposal of spent nuclear fuel.

The Palo Verde participants have contracted for all of Palo Verde's requirements for uranium concentrates and conversion services through 2008, except for a small percentage of 2003 uranium concentrates and 2004 conversion requirements that will be obtained under contracts currently being finalized. The Palo Verde participants have also contracted for all of Palo Verde's enrichment services through 2010 and fuel assembly fabrication services until at least 2015.

**Spent Nuclear Fuel and Waste Disposal** Nuclear power plant operators are required to enter into spent nuclear fuel disposal contracts with the DOE, and the DOE is required to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE has announced that the repository cannot be completed before 2010 and that it does not intend to begin accepting spent nuclear fuel prior to that date. In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision preventing the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities filed damages lawsuits against the DOE in the Court of Federal Claims.

In February 2002, the U.S. Secretary of Energy recommended to President Bush that the Yucca Mountain, Nevada site be developed as a permanent repository for spent nuclear fuel. The President transmitted this recommendation to Congress and the State of Nevada vetoed the President's recommendation. In July 2002, Congress approved the development of the Yucca Mountain, Nevada site, overriding the Nevada veto. It is now expected that the DOE will submit a license application to the NRC late in 2004. The State of Nevada has filed several lawsuits relating to the Yucca Mountain site. We cannot currently predict what further steps will be taken in this area.

Facility funding is a further complication. While all nuclear utilities pay an amount calculated on the basis of the output of their respective plants into a so-called nuclear waste fund the annual Congressional appropriations for the permanent repository have been for amounts less than the amounts paid into the waste fund (the balance of which is being used for other purposes).

We have existing fuel storage pools at Palo Verde and have completed a new facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, we believe that spent nuclear fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit. See "Palo Verde Nuclear Generating Station" in Note 10 of Notes to Financial Statements in Item 8 for a discussion of interim spent nuclear fuel storage costs.

Although some low-level waste has been stored on-site in a low-level waste facility, we are currently shipping low-level waste to off-site facilities. We currently believe that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

We believe that scientific and financial aspects of the issues of spent nuclear fuel and low-level waste storage and disposal can be resolved satisfactorily. However, we acknowledge that their ultimate resolution in a timely fashion will require political resolve and action on national and regional scales which we are less able to predict. We expect to vigorously protect and pursue our rights related to this matter.

**Purchased Power Agreements**

In addition to that available from our own generating capacity (see "Properties" in Item 2), we purchase electricity under various arrangements. One of the most important of these is a long-term contract with Salt River Project. The amount of electricity available to us is based in large part on customer demand within certain areas now served by us pursuant to a related territorial agreement. The generating capacity available to us pursuant to the contract was 336 MW from January through May 2002, and starting in June 2002, it changed to 343 MW. In 2002, we received approximately 1,104,973 MWh of energy under the contract and paid about $46.2 million for capacity availability and energy received. This contract may be canceled by Salt River Project on three years' notice, given no earlier than December 31, 2003. We may also cancel the contract on five years' notice, given no earlier than December 31, 2006.

In September 1990, we entered into a thirty-year seasonal capacity exchange agreement with PacifiCorp. Under this agreement, we receive electricity from PacifiCorp during the summer peak season (from May 15 to September 15) and we return electricity to PacifiCorp during the winter season (from October 15 to February 15). Until 2020, we and PacifiCorp each has 480 MW of capacity and a related amount of energy available to it under the agreement for its respective seasons. In 2002, we received approximately 571,392 MWh of energy under the capacity exchange. We must also make additional offers of energy to PacifiCorp each year through October 31, 2020. Pursuant to this requirement, during 2002, PacifiCorp received offers of 1,129,600 MWh and purchased about 115,750 MWh.

**Construction Program**

During the years 2000 through 2002, we incurred approximately $1.4 billion in capital expenditures. Our capital expenditures for the years 2003 through 2005 are expected to be primarily for expanding transmission and distribution capabilities to meet growing customer needs, for upgrading existing utility property and for environmental purposes. Our capital expenditures were approximately $501 million in 2002. Our capital expenditures, including expenditures for environmental control facilities, for the years 2003 through 2005 have been estimated as follows:

(dollars in millions)

| By Year | | By Major Facilities | |
|---|---|---|---|
| 2003 | $ 401 | Production | $ 386 |
| 2004 | 379 | T&D | 877 |
| 2005 | 498 | Other | 15 |
| Total | $ 1,278 | Total | $ 1,278 |

The above amounts exclude capitalized interest costs and include capitalized property taxes and approximately $30 million per year for nuclear fuel. These amounts include only our generation (production) assets. We conduct a continuing review of our construction program.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Needs and Resources" in Item 7 for additional information about our construction program.

**Mortgage Replacement Fund Requirements**

So long as any of our first mortgage bonds are outstanding, we are required for each calendar year to deposit with the trustee under our mortgage cash in a formularized amount related to net additions to our mortgaged utility plant. We may satisfy all or any part of this "replacement fund" requirement by using redeemed or retired bonds, net property additions or property retirements. For 2002, the replacement fund requirement amounted to approximately $161 million. Certain of the bonds we have issued under the mortgage that are callable prior to maturity are redeemable at their par value plus accrued interest with cash we deposit in the replacement fund. These call provisions are subject in many cases to a period of time after the original issuance of the bonds during which they may not be redeemed in this manner. See Note 6 of Notes to Financial Statements in Item 8 for information regarding our first mortgage bonds.

**Environmental Matters**

**EPA Environmental Regulation**

**Clean Air Act** We are subject to a number of requirements under the Clean Air Act. The Clean Air Act addresses, among other things:

- "acid rain";
- visibility in certain specified areas;
- hazardous air pollutants; and
- areas that have not attained national ambient air quality standards.

With respect to "acid rain," the Clean Air Act established a system of sulfur dioxide emissions "allowances" to offset each ton of sulfur dioxide emitted by affected power plants. Based on EPA allowance allocations, we will have sufficient allowances to permit continued operation of our plants at current levels without installing additional equipment. The Clean Air Act also requires the EPA to set nitrogen oxides emissions limitations for certain coal-fired units. The EPA rule allows emissions from all units in a plant to be averaged to demonstrate compliance with the emission limitation. Currently, nitrogen oxides emissions from all of our units are within the limitations specified under the EPA's rules. We do not currently expect this rule to have a material impact on our financial position, results of operations or liquidity.

The Clean Air Act required the EPA to establish a Grand Canyon Visibility Transport Commission to complete a study on visibility impairment in sixteen "Class I Areas" (large national parks and wilderness areas) on the Colorado Plateau. The Navajo Generating Station, Cholla and Four Corners are located near several Class I Areas on the Colorado Plateau. The Visibility

Commission completed its study and on June 10, 1996 submitted its final recommendations to the EPA.

On April 22, 1999, the EPA announced final regional haze rules. These new regulations require states to submit, by 2008, implementation plans to eliminate all man-made emissions causing visibility impairment in certain specified areas, including Class I Areas in the Colorado Plateau. The 2008 implementation plans must also include consideration and potential application of best available retrofit technology for major stationary sources which came into operation between August 1962 and August 1977, such as the Navajo Generating Station, Cholla and Four Corners.

The rules allow the nine western states and tribes that participated in the Visibility Commission process to follow an alternate implementation plan and schedule for the Class I Areas considered by the Visibility Commission. Under this option, those states and tribes would submit implementation plans by 2003, which would incorporate certain regional sulfur dioxide emissions milestones for the years 2003, 2008, 2013 and 2018 (which include the application of best available retrofit technology). If the regional emissions in those years were within those milestones, there would be no further emission reduction requirements, and if they were exceeded, then an emission trading program would be implemented to maintain the emissions within those milestones.

The EPA reviewed an "Annex" to the Visibility Commission recommendations that specify the regional sulfur dioxide emission milestones. On April 26, 2002, the EPA proposed to accept the Visibility Commission's Annex, which had been submitted by the Western Regional Air Partnership (successor to Visibility Commission) in September 2000. The Annex specifies regional sulfur dioxide emission reduction milestones. The EPA's final approval of the Annex would allow the states and tribes to pursue the alternate implementation of the regional haze rules through 2018. Any states and tribes that implement this option would have to submit state implementation plans by 2003 to address visibility in areas identified in the process, and revised implementation plans in 2008 to address Class I Areas which were not included in the process. The State of Arizona is in the process of developing a State Implementation Plan to implement the provisions of the Annex. Because Four Corners is located on the Navajo Reservation and is currently regulated by EPA Region IX, the provisions of the Annex currently could become applicable to Four Corners only through a Federal Implementation Plan promulgated by EPA Region IX. At this time, it is uncertain how the State of Arizona and/or EPA Region IX will proceed to implement the Annex, so the actual impact on us cannot yet be determined.

In July 1997, the EPA promulgated final National Ambient Air Quality Standards for ozone and particulate matter. Pursuant to these rules, the ozone standard is more stringent and a new ambient standard for very fine particles has been established. Congress has enacted legislation that could delay the implementation of regional haze requirements and the particulate matter ambient standard; however, the legislation does not preclude the Visibility Commission states and tribes from implementing the alternate regional haze rules discussed above. Because the actual level of emissions controls, if any, for any unit cannot be determined at this time, we currently cannot estimate the capital expenditures, if any, which would result from the final rules. However, we do not currently expect these rules to have a material adverse effect on our financial position, results of operations or liquidity.

With respect to hazardous air pollutants emitted by electric utility steam generating units, the EPA has determined that mercury emissions and other hazardous air pollutants from coal and oil-fired power plants will be regulated. We expect that the EPA will propose specific rules for this

purpose in 2003 and finalize them by 2004, with compliance required by 2008. Because the ultimate requirements that the EPA may impose are not yet known, we cannot currently estimate the capital expenditures, if any, which may be required.

Certain aspects of the Clean Air Act may require us to make related expenditures, such as permit fees. We do not expect any of these expenditures to have a material impact on our financial position, results of operations or liquidity.

**Federal Implementation Plan** In September 1999, the EPA proposed a FIP to set air quality standards at certain power plants, including the Navajo Generating Station and Four Corners. The comment period on this proposal ended in November 1999. The FIP is similar to current Arizona regulation of the Navajo Generating Station and New Mexico regulation of Four Corners, with minor modifications. We do not currently expect the FIP to have a material impact on our financial position, results of operations or liquidity.

**Superfund** The Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties. PRPs may be strictly, and often jointly and severally, liable for clean-up. The EPA had previously advised us that the EPA considers us to be a PRP in the Indian Bend Wash Superfund Site, South Area. Our Ocotillo Power Plant is located in this area. Based on the information to date, including available insurance coverage and an EPA estimate of cleanup costs, we do not expect this matter to have a material impact on our financial position, results of operations or liquidity.

**Manufactured Gas Plant Sites** We are currently investigating properties which we now own or which were previously owned by us or our corporate predecessors, that were at one time sites of, or sites associated with, manufactured gas plants. The purpose of this investigation is to determine if:

- waste materials are present;
- such materials constitute an environmental or health risk; and
- we have any responsibility for remedial action.

Where appropriate, we have begun clean-up of certain of these sites. We do not expect these matters to have a material adverse effect on our financial position, results of operations or liquidity.

**Arizona Department of Environmental Quality**

ADEQ issued to us NOVs, dated September 25, 2001 and October 15, 2001 alleging, among other things, the burning of unauthorized materials and storage of hazardous waste without a permit at the Cholla Power Plant. Each NOV requires us to achieve and document compliance with specific environmental requirements. We have submitted responses to the NOVs as well as additional information requested by the agency. By letter dated February 28, 2003, the Arizona Attorney General notified us that the ADEQ expects to take enforcement action against us regarding the violations included in the NOVs, as well as related violations. We do not expect these matters to have a material adverse effect on our financial position, results of operations or liquidity.

**Navajo Nation Environmental Issues**

Four Corners and the Navajo Generating Station are located on the Navajo Reservation and are held under easements granted by the federal government as well as leases from the Navajo Nation. We are the Four Corners operating agent. We own a 100% interest in Four Corners Units 1, 2 and 3, and a 15% interest in Four Corners Units 4 and 5. We own a 14% interest in Navajo Generating Station Units 1, 2 and 3.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act and the Navajo Nation Pesticide Act (collectively, the Navajo Acts). The Navajo Acts purport to give the Navajo Nation Environmental Protection Agency authority to promulgate regulations covering air quality, drinking water and pesticide activities, including those that occur at Four Corners and the Navajo Generating Station. The Four Corners and Navajo Generating Station participants dispute that purported authority, and by separate letters dated October 12 and October 13, 1995, the Four Corners participants and the Navajo Generating Station participants requested the United States Secretary of the Interior to resolve their dispute with the Navajo Nation regarding whether or not the Navajo Acts apply to operations of Four Corners and the Navajo Generating Station. On October 17, 1995, the Four Corners participants and the Navajo Generating Station participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that:

- their respective leases and federal easements preclude the application of the Navajo Acts to the operations of Four Corners and the Navajo Generating Station; and

- the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Navajo Acts as applied to Four Corners and the Navajo Generating Station.

On October 18, 1995, the Navajo Nation and the Four Corners and Navajo Generating Station participants agreed to indefinitely stay these proceedings so that the parties may attempt to resolve the dispute without litigation. The Secretary and the Court have stayed these proceedings pursuant to a request by the parties. We cannot currently predict the outcome of this matter.

In February 1998, the EPA issued regulations identifying those Clean Air Act provisions for which it is appropriate to treat Indian tribes in the same manner as states. The EPA has announced that it has not yet determined whether the Clean Air Act would supersede pre-existing binding agreements between the Navajo Nation and the Four Corners participants and the Navajo Generating Station participants that could limit the Navajo Nation's environmental regulatory authority over the Navajo Generating Station and Four Corners. We believe that the Clean Air Act does not supersede these pre-existing agreements. We cannot currently predict the outcome of this matter.

In April 2000, the Navajo Tribal Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. We believe that the regulations fail to recognize that the Navajo Nation did not intend to assert jurisdiction over Four Corners and the Navajo Generating Station. On July 12, 2000, the Four Corners participants and the Navajo Generating Station participants each filed a petition with the Navajo Supreme Court for review of the operating permit regulations. We cannot currently predict the outcome of this matter.

**Water Supply**

Assured supplies of water are important for our generating plants. At the present time, we have adequate water to meet our needs. However, conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions.

Both groundwater and surface water in areas important to our operations have been the subject of inquiries, claims and legal proceedings, which will require a number of years to resolve. We are one of a number of parties in a proceeding before a state court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. (State of New Mexico, in the relation of S.E. Reynolds, State Engineer vs. United States of America, City of Farmington, Utah International, Inc., et al., San Juan County, New Mexico, District Court No. 75-184). An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for a then-agreed upon cost, sufficient water from our allocation to offset the loss.

A summons served on us in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Maricopa County, Arizona, Superior Court. (In re The General Adjudication of All Rights to Use Water in the Gila River System and Source, Supreme Court Nos. WC-79-0001 through WC 79-0004 (Consolidated) [WC-1, WC-2, WC-3 and WC-4 (Consolidated)], Maricopa County Nos. W-1, W-2, W-3 and W-4 (Consolidated)). Palo Verde is located within the geographic area subject to the summons. Our rights and the rights of the Palo Verde participants to the use of groundwater and effluent at Palo Verde are potentially at issue in this action. As project manager of Palo Verde, we filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, we seek confirmation of such rights. Three of our other power plants and two of Pinnacle West Energy's power plants are also located within the geographic area subject to the summons. Our claims dispute the court's jurisdiction over our groundwater rights with respect to these plants. Alternatively, we seek confirmation of such rights. In November 1999, the Arizona Supreme Court issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. In addition, in September 2000, the Arizona Supreme Court issued a decision affirming the lower court's criteria for resolving groundwater claims. Litigation on both of these issues will continue in the trial court. No trial date concerning our water rights claims has been set in this matter.

We have also filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County, Arizona, Superior Court. (In re The General Adjudication of All Rights to Use Water in the Little Colorado River System and Source, Supreme Court No. WC-79-0006 WC-6, Apache County No. 6417). Our groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and is therefore potentially at issue in the case. Our claims dispute the court's jurisdiction over our groundwater rights. Alternatively, we seek confirmation of such rights. A number of parties are in the process of settlement negotiations with respect to certain claims in this matter. Other claims have been identified as ready for litigation in motions filed with the court. No trial date concerning our water rights claims has been set in this matter.

Although the foregoing matters remain subject to further evaluation, we expect that the described litigation will not have a material adverse impact on our financial position, results of operations or liquidity.

The Four Corners region, in which Four Corners is located, has been experiencing drought conditions that may affect the water supply for the plants in 2003, as well as later years if adequate moisture is not received in the watershed that supplies the area. Various stakeholders in the San Juan Basin, including the New Mexico State Engineer, are evaluating how water rights might be affected by the drought conditions, including water rights pursuant to the New Mexico state permit that provide approximately 30,000 acre feet of water to Four Corners. We are assessing alternatives for temporary supplies of water and are working with area stakeholders to minimize the effect, if any, on operations of the plant. The effect of the drought cannot be fully assessed at this time, and we cannot predict the ultimate outcome, if any, of the drought or whether the drought will adversely affect the amount of power available, or the price thereof, from Four Corners.

## ITEM 2. PROPERTIES

### Net Accredited Capacity

Our present generating facilities have net accredited capacities as follows:

| | Capacity(kW) |
|---|---|
| Coal: | |
| Units 1, 2 and 3 at Four Corners | 560,000 |
| 15% owned Units 4 and 5 at Four Corners | 222,000 |
| Units 1, 2 and 3 at Cholla Plant | 615,000 |
| 14% owned Units 1, 2 and 3 at the Navajo Plant | 315,000 |
| Subtotal | 1,712,000 |
| Gas or Oil: | |
| Two steam units at Ocotillo and two steam units at Saguaro | 430,000(a) |
| Eleven combustion turbine units | 493,000 |
| Three combined cycle units | 255,000 |
| Subtotal | 1,178,000 |
| Nuclear: | |
| 29.1% owned or leased Units 1, 2, and 3 at Palo Verde | 1,086,300 |
| Hydro and Solar | 7,600 |
| Total | 3,983,900 |

(a) Does not include West Phoenix steam units (108,300 kW), which were retired in December 2002.

## Reserve Margin

Our 2002 peak one-hour demand on our electric system was recorded on July 9, 2002 at 5,802,900 kW, compared to the 2001 peak of 5,687,200 kW recorded on July 2, 2001. Taking into account additional capacity then available to us under long-term purchase power contracts as well as our and Pinnacle West Energy's generating capacity, our capability of meeting system demand on July 9, 2002, amounted to 6,046,600 kW, for an installed reserve margin of 6.5%. The power actually available to us from our resources fluctuates from time to time due in part to planned outages and technical problems. The available capacity from sources actually operable at the time of the 2002 peak amounted to 3,877,600 kW, for a margin of negative 38.1%. Firm purchases totaling 2,612,000 kW, including short-term seasonal purchases and unit contingent purchases were in place at the time of the peak ensuring the ability to meet the load requirement, with an actual reserve margin of 7.1%.

See "Purchased Power Agreements" in Item 1 for information about certain of our long-term power agreements.

## Plant Sites Leased from Navajo Nation

The Navajo Generating Station and Four Corners are located on land held under easements from the federal government and also under leases from the Navajo Nation. These are long-term agreements with options to extend, and we do not believe that the risk with respect to enforcement of these easements and leases is material. The majority of coal contracted for use in these plants and certain associated transmission lines are also located on Indian reservations. See "Purchased Power and Generating Fuel - Coal Supply" in Item 1.

## Palo Verde Nuclear Generating Station

### Palo Verde Leases

See Note 8 of Notes to Financial Statements in Item 8 for a discussion of three sale-leaseback transactions related to Palo Verde Unit 2.

### Regulatory

Operation of each of the three Palo Verde units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986 and Unit 3 in November 1987. The full power operating licenses, each valid for a period of approximately 40 years, authorize us, as operating agent for Palo Verde, to operate the three Palo Verde units at full power.

### Nuclear Decommissioning Costs

The NRC rules on financial assurance requirements for the decommissioning of nuclear power plants provide that a licensee may use a trust as the exclusive financial assurance mechanism if the licensee recovers estimated total decommissioning costs through cost of service rates or through a "non-bypassable charge." The "non-bypassable systems benefits" charge is the charge that the ACC has approved to recover certain types of ACC-approved costs, including costs for low income programs, demand side management, consumer education, environmental, renewables, etc.

"Non-bypassable" means that if a customer chooses to take energy from an "energy service provider" other than us, the customer will still have to pay this charge to us as part of the customer's electric bill. Other mechanisms are prescribed, including prepayment, if the requirements for exclusive reliance on the external sinking fund mechanism are not met. We currently rely on the external sinking fund mechanism to meet the NRC financial assurance requirements for our interests in Palo Verde Units 1, 2 and 3. The decommissioning costs of Palo Verde Units 1, 2 and 3 are currently included in our ACC jurisdictional rates. ACC retail electric competition Rules provide that decommissioning costs would be recovered through a non-bypassable "system benefits" charge, which would allow us to maintain our external sinking fund mechanism. See Note 11 of Notes to Financial Statements in Item 8 for additional information about our nuclear decommissioning costs.

**Palo Verde Liability and Insurance Matters**

See "Palo Verde Nuclear Generating Station" in Note 10 of Notes to Financial Statements in Item 8 for a discussion of the insurance maintained by the Palo Verde participants, including us, for Palo Verde.

**Property Not Held in Fee or Subject to Encumbrances**

**Jointly-Owned Facilities**

We share ownership of some of our generating and transmission facilities with other companies. The following table shows our interest in those jointly-owned facilities recorded on the Balance Sheets at December 31, 2002:

| | Percent Owned by Us |
|---|---|
| Generating facilities: | |
| Palo Verde Nuclear Generating Station Units 1 and 3 | 29.1% |
| Palo Verde Nuclear Generating Station Unit 2 (see "Palo Verde Leases" below) | 17.0% |
| Four Corners Steam Generating Station Units 4 and 5 | 15.0% |
| Navajo Steam Generating Station Units 1, 2, and 3 | 14.0% |
| Cholla Steam Generating Station Common Facilities (a) | 62.8%(b) |
| Transmission facilities: | |
| ANPP 500KV System | 35.8%(b) |
| Navajo Southern System | 31.4%(b) |
| Palo Verde-Yuma 500KV System | 23.9%(b) |
| Four Corners Switchyards | 27.5%(b) |
| Phoenix-Mead System | 17.1%(b) |
| Palo Verde – Estrella 500KV System | 50.0%(b) |

(a) PacifiCorp owns Cholla Unit 4 and we operate the unit for PacifiCorp. The common facilities at the Cholla Plant are jointly-owned.

(b) Weighted average of interests.

**Palo Verde Leases**

In 1986, we sold about 42% of our share of Palo Verde Unit 2 and certain common facilities in three separate sale-leaseback transactions. We account for these leases as operating leases. The leases, which have terms of 29.5 years, contain options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. See Notes 8 and 18 of Notes to Financial Statements in Item 8 for additional information regarding the Palo Verde Unit 2 sale-leaseback transactions.

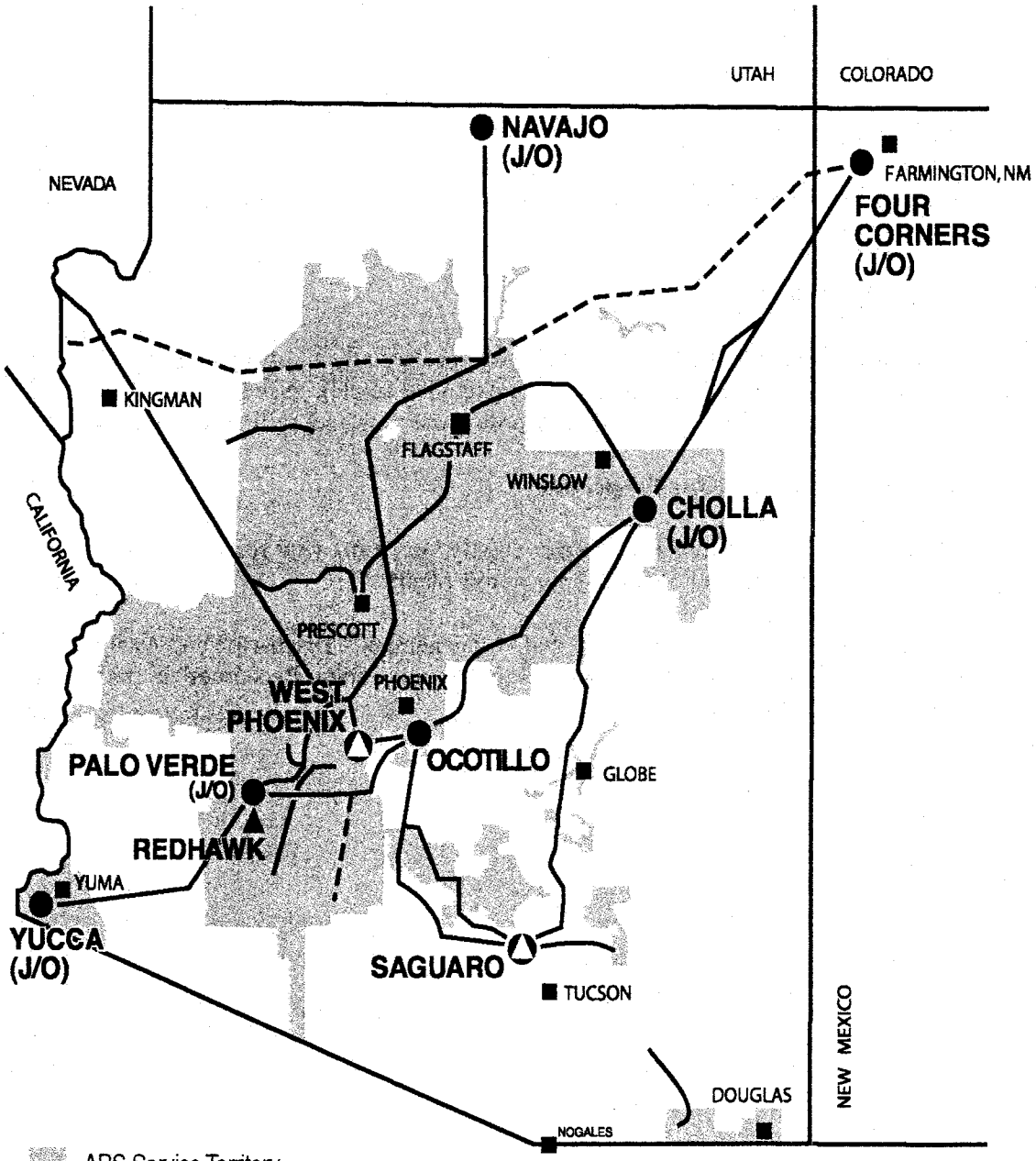
**First Mortgage Lien**

Our first mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment and other excluded assets). See Note 6 of Notes to Financial Statements in Item 8 for information regarding our outstanding first mortgage bonds.

**Other Information Regarding Our Properties**

See "Environmental Matters" and "Water Supply" in Item 1 with respect to matters having possible impact on the operation of certain of our power plants.

See "Construction Program" in Item 1 and "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" in Item 7 for a discussion of our construction plans.




APS Service Territory

Major APS Power Plants (J/O = Joint Ownership)

Pinnacle West Energy Plants

Plants Jointly Owned by APS and Pinnacle West Energy

Principal APS Transmission Lines

Transmission Lines Operated for Others

## ITEM 3. LEGAL PROCEEDINGS

See "Environmental Matters" and "Water Supply" in Item 1 in regard to pending or threatened litigation and other disputes. See Note 3 of Notes to Financial Statements in Item 8 for a discussion of the ACC retail electric competition Rules, the Track A Order and related litigation.

See Note 10 of Notes to Financial Statements in Item 8 for information relating to the FERC proceedings on California energy market issues and a claim by Citizens that we overcharged Citizens under a power service agreement.

## ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

## PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK AND RELATED STOCKHOLDER MATTERS

Our common stock is wholly-owned by Pinnacle West and is not listed for trading on any stock exchange. As a result, there is no established public trading market for our common stock.

The chart below sets forth the dividends declared on the Company's common stock for each of the four quarters for 2002 and 2001.

**Common Stock Dividends**
**(Dollars in Thousands)**

| Quarter | 2002 | 2001 |
|---|---|---|
| 1st Quarter | $42,500 | $42,500 |
| 2nd Quarter | 42,500 | 42,500 |
| 3rd Quarter | 42,500 | 42,500 |
| 4th Quarter | 42,500 | 42,500 |

After payment or setting aside for payment of cumulative dividends and mandatory sinking fund requirements, where applicable, on all outstanding issues of preferred stock, the holders of common stock are entitled to dividends when and as declared out of funds legally available therefor. See Note 6 of Notes to Financial Statements in Item 8 for restrictions on retained earnings available for the payment of common stock dividends. As of December 31, 2002, we did not have any outstanding preferred stock.

## ITEM 6. SELECTED FINANCIAL DATA

| | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| | | | (dollars in thousands) | | |
| Electric operating revenues: | | | | | |
| Regulated electricity segment | $ 2,059,339 | $ 2,562,088 | $ 2,538,750 | $ 1,914,722 | $ 1,741,148 |
| Marketing and trading segment | 34,054 | 549,240 | 395,392 | 154,126 | 180,145 |
| Purchased power and fuel costs: | | | | | |
| Regulated electricity segment | 595,368 | 1,227,188 | 1,065,596 | 432,844 | 306,884 |
| Marketing and trading segment | 32,662 | 313,991 | 267,032 | 136,522 | 151,164 |
| Operating expenses | 1,136,363 | 1,171,171 | 1,155,278 | 1,115,664 | 1,097,471 |
| Operating income | 329,000 | 398,978 | 446,236 | 383,818 | 365,774 |
| Other income/(deductions) | (8,041) | (79) | (6,545) | 20,857 | 20,315 |
| Interest deductions – net | 121,616 | 118,211 | 133,097 | 136,353 | 130,842 |
| Income before extraordinary charge and cumulative effect adjustment | 199,343 | 280,688 | 306,594 | 268,322 | 255,247 |
| Extraordinary charge – net of tax (a) | -- | -- | -- | (139,885) | -- |
| Cumulative effect of change in accounting – net of tax (b) | -- | (15,201) | -- | -- | -- |
| Net income | 199,343 | 265,487 | 306,594 | 128,437 | 255,247 |
| Preferred dividends | -- | -- | -- | 1,016 | 9,703 |
| Earnings for common stock | $ 199,343 | $ 265,487 | $ 306,594 | $ 127,421 | $ 245,544 |
| Total Assets | $ 6,521,807 | $ 6,225,733 | $ 6,349,609 | $ 6,079,307 | $ 6,356,534 |
| Capital Structure: | | | | | |
| Common stock equity | $ 2,159,312 | $ 2,150,690 | $ 2,119,768 | $ 1,983,174 | $ 1,975,755 |
| Non-redeemable preferred stock | -- | -- | -- | -- | 85,840 |
| Redeemable preferred stock | -- | -- | -- | -- | 9,401 |
| Long-term debt less current maturities | 2,217,340 | 1,949,074 | 1,806,908 | 1,997,400 | 1,876,540 |
| Total capitalization | 4,376,652 | 4,099,764 | 3,926,676 | 3,980,574 | 3,947,536 |
| Commercial paper | -- | 171,162 | 82,100 | 38,300 | 178,830 |
| Current maturities of long-term debt | 3,503 | 125,451 | 250,266 | 114,711 | 164,378 |
| Total | $ 4,380,155 | $ 4,396,377 | $ 4,259,042 | $ 4,133,585 | $ 4,290,744 |

(a) Changes associated with a regulatory disallowance. See "Regulatory Accounting" in Note 1.
(b) Change in accounting standards related to derivatives in 2001. See Note 16

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 for a discussion of certain information in the table above.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### INTRODUCTION

In this Item, we explain our results of operations, general financial condition, and outlook including:

- the changes in our earnings from 2001 to 2002 and from 2000 to 2001;
- our capital needs, liquidity and capital resources;
- our critical accounting policies;
- our business outlook and major factors that affect our financial outlook; and
- our management of market risks.

Throughout this Item, we refer to specific "Notes" in the Notes to Financial Statements in Item 8 of this report. These Notes add further details to the discussion.

### BUSINESS OVERVIEW

We are an electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about half of the Phoenix metropolitan area. Electricity is delivered through a distribution system that we own. We also generate, sell and deliver electricity to wholesale customers in the western United States. Our marketing and trading division sells, in the wholesale market, our and Pinnacle West Energy's generation output that is not needed for our Native Load, which includes loads for retail customers and traditional cost-of-service wholesale customers. We do not distribute any products. Pinnacle West owns all of our outstanding common stock.

### SUMMARY OF KEY FACTORS AFFECTING OUR FINANCIAL OUTLOOK

We believe the following are among the key factors affecting our financial outlook:

- The following ACC regulatory matters:
  - Our $500 million financing application, which the ACC approved on March 27, 2003;
  - The implementation of the ACC-mandated process by which we must competitively procure energy; and
  - Our general rate case to be filed in 2003.
- Wholesale power market conditions in the western United States.

We discuss each of these, and other, factors in detail below in the section entitled "Factors Affecting Our Financial Outlook."

## BUSINESS SEGMENTS

We have two principal business segments (determined by services and the regulatory environment):

- our regulated electricity segment, which consists of regulated traditional retail and wholesale electricity businesses and related activities, and includes electricity transmission, distribution and generation; and

- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading.

The following is a summary of earnings by business segment for the years ended December 31, 2002, 2001, and 2000 (dollars in millions):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Regulated electricity | $ 198 | $ 138 | $ 228 |
| Marketing and trading | 1 | 142 | 79 |
| Income before accounting change | 199 | 280 | 307 |
| Cumulative effect of change in accounting – net of income taxes (a) | -- | (15) | -- |
| Net income | $ 199 | $ 265 | $ 307 |

(a) We recorded a $15 million after-tax charge in 2001 for the cumulative effect of a change in accounting for derivatives related to the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." See Note 16.

See Note 15 for additional financial information regarding our business segments.

## RESULTS OF OPERATIONS

### General

Throughout the following explanations of our results of operations, we refer to "gross margin." With respect to our regulated electricity segment and marketing and trading segment, gross margin refers to electric operating revenues less purchased power and fuel costs.

### 2002 Compared with 2001

Our net income for the year ended December 31, 2002 was $199 million compared with $265 million for the prior year. In 2001, we recognized a $15 million after-tax charge for the cumulative effect of a change in accounting for derivatives, as required by SFAS No. 133 (see Note 16).

Our income before accounting change for the year ended December 31, 2002 was $199 million compared with $281 million for the prior year. The period-to-period comparison was lower due to reduced marketing and trading segment gross margin due to our transfer of the marketing and trading activities to Pinnacle West in 2001 and severance costs of $34 million in the second half of 2002 relating to voluntary workforce reductions. These decreases were partially offset by increased earnings contributions from our regulated electricity activities, reflecting lower replacement power costs for power plant outages, retail customer growth and higher average usage per customer, and lower purchased power costs related to 2001 generation reliability program (the addition of generating capability to enhance reliability for the summer of 2001). These increases were partially offset by the effects of milder weather, retail electricity price decreases and higher costs for purchased power and gas due to higher hedged gas and power prices.

For additional details, see the following discussion.

The major factors that increased (decreased) income before accounting change were as follows (dollars in millions):

| | Increase (Decrease) |
|---|---|
| Regulated electricity segment gross margin: | |
| Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages | $ 127 |
| Increased purchased power and fuel costs due to higher hedged gas and power prices, partially offset by improved hedge management, net of mark-to-market reversals | (24) |
| Lower purchased power and fuel costs related to the 2001 generation reliability program | 30 |
| Higher retail sales volumes due to customer growth and higher average usage, excluding weather effects | 38 |
| 2001 charges related to purchased power contracts with Enron and its affiliates | 13 |
| Retail price reductions effective July 1, 2001 and July 1, 2002 | (28) |
| Effects of milder weather on retail sales | (27) |
| Net increase in regulated electricity segment gross margin | 129 |
| Marketing and trading segment gross margin: | |
| Decrease in generation sales other than Native Load due to lower market prices partially offset by higher sales volumes | (78) |
| Decrease in marketing and trading segment margin resulting from our transfer of marketing and trading activities to Pinnacle West in 2001 | (156) |
| Net decrease in marketing and trading segment gross margin | (234) |
| Net decrease in regulated electricity and marketing and trading segments' gross margins | (105) |
| Higher operations and maintenance expense related to 2002 severance costs of approximately $34 million, partially offset by lower generation reliability costs | (30) |
| Lower depreciation and amortization expense primarily related to lower regulatory asset amortization | 21 |
| Higher taxes other than income taxes | (7) |
| Lower other income primarily due to a 2001 insurance recovery of environmental remediation costs | (15) |
| Higher net interest expense primarily due to higher debt balances and lower capitalized interest | (3) |
| Miscellaneous factors, net | 2 |
| Net decrease in income before income taxes | (137) |
| Lower income taxes primarily due to lower income | 56 |
| Net decrease in income before accounting change | $ (81) |

**Regulated Electricity Segment Gross Margin**

Regulated electricity segment revenues related to our regulated retail and wholesale electricity businesses were $503 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased revenues related to traditional wholesale sales as a result of lower sales volumes and lower prices ($64 million);
- decreased revenues related to retail load hedge management wholesale sales, primarily as a result of lower prices and lower sales volumes ($421 million);
- decreased retail revenues related to milder weather ($60 million);
- increased retail revenues related to customer growth and higher average usage, excluding weather effects ($69 million);
- decreased retail revenues related to reductions in retail electricity prices ($28 million); and
- other miscellaneous factors ($1 million net increase).

Regulated electricity segment purchased power and fuel costs were $632 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased costs related to traditional wholesale sales as a result of lower sales volumes and lower prices ($64 million);
- decreased costs related to retail load hedge management wholesale sales, primarily as a result of lower prices and lower sales volumes ($426 million);
- increased costs related to higher prices for hedged natural gas and purchased power, net of mark-to-market reversals ($29 million);
- lower purchased power costs related to the 2001 generation reliability program ($30 million);
- decreased costs related to the effects of milder weather on retail sales ($33 million);
- increased costs related to retail sales growth, excluding weather effects ($31 million);
- charges in 2001 related to purchased power contracts with Enron and its affiliates ($13 million net decrease);
- decreased replacement power costs for power plant outages due to lower market prices and fewer unplanned outages ($127 million); and
- other miscellaneous factors ($1 million net increase).

**Marketing and Trading Segment Gross Margin**

Marketing and trading segment revenues were $515 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased revenues from generation sales other than Native Load primarily due to lower market prices partially offset by higher sales volumes ($128 million); and
- lower marketing and trading revenues as a result of our transfer of marketing and trading activities to Pinnacle West in 2001 ($387 million).

Marketing and trading segment purchased power and fuel costs were $281 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased fuel costs related to generation sales other than Native Load primarily because of lower natural gas prices partially offset by higher sales volumes ($50 million); and

- lower marketing and trading purchased power and fuel costs as a result of our transfer of marketing and trading activities to Pinnacle West in 2001 ($231 million).

**Other Income Statement Items**

The increase in operations and maintenance expense of $30 million was primarily due to severance costs of $34 million related to a 2002 voluntary workforce reduction, partially offset by lower costs related to generation reliability, plant outages and maintenance costs.

The increase in taxes other than income taxes of $7 million is primarily due to increased property taxes on higher property balances.

Other income decreased $15 million primarily due to an insurance recovery recorded in 2001 related to environmental remediation costs and other costs (see Note 17).

The decrease in depreciation and amortization expense of $21 million primarily related to lower regulatory asset amortization, in accordance with the 1999 Settlement Agreement, partially offset by increased depreciation and amortization on higher property, plant and equipment balances.

**2001 Compared with 2000**

Our net income for the year ended December 31, 2001 was $265 million compared with $307 million for the year ended December 31, 2000. In 2001, we recognized a $15 million after-tax charge in net income as a cumulative effect of a change in accounting for derivatives, as required by SFAS No. 133 (see Note 16).

Income before accounting change for the year ended December 31, 2001 was $281 million compared with $307 million for the year ended December 31, 2000. The year-to-year comparison benefited from strong marketing and trading results and retail customer growth. These factors were partially offset by higher purchased power and fuel costs, due in part to increased power plant maintenance; generation reliability measures; continuing retail electricity price decreases; and a charge related to Enron and its affiliates.

For additional details, see the following discussion.

The major factors that increased (decreased) income before accounting change were as follows (dollars in millions):

| | Increase (Decrease) |
|---|---|
| Regulated electricity segment gross margin: | |
| Higher replacement power costs for plant outages related to higher market prices | $ (70) |
| Retail price reductions effective July 1, 2001 and July 1, 2000 | (27) |
| Charges related to purchased power contracts with Enron and its affiliates (a) | (13) (a) |
| Higher purchased power costs related to the 2001 generation reliability program | (30) |
| Miscellaneous revenues | 1 |
| Net decrease in regulated electricity segment gross margin | (139) |
| Marketing and trading segment gross margin: | |
| Increase from generation sales other than Native Load due to higher market prices | 25 |
| Higher realized wholesale margin net of related mark-to-market reversals | 11 |
| Increase in mark-to-market value related to future periods | 71 |
| Net increase in marketing and trading segment gross margin | 107 |
| Net increase in regulated electricity and marketing and trading segments' gross margins | (32) |
| Higher operations and maintenance expense related to the 2001 generation reliability program | (12) |
| Higher operations and maintenance expense related primarily to employee benefits, plant outage and maintenance and other costs | (23) |
| Lower net interest expense primarily due to higher capitalized interest | 15 |
| Higher other income primarily due to a 2001 insurance recovery of environmental remediation costs | 11 |
| Miscellaneous factors, net | 2 |
| Net decrease in income before income taxes | (39) |
| Lower income taxes primarily due to lower income | 13 |
| Net decrease in income before accounting change | $ (26) |

(a) We recorded charges totaling $13 million before income taxes for exposure to Enron and its affiliates in the fourth quarter of 2001.

**Regulated Electricity Segment Gross Margin**

Regulated electricity segment revenues related to our regulated retail and wholesale electricity businesses were $23 million higher in the year ended December 31, 2001 compared with the prior year as a result of:

- decreased revenues related to other wholesale sales and miscellaneous revenues as a result of lower sales volumes ($28 million);
- increased retail revenues primarily related to higher sales volumes primarily due to customer growth ($78 million); and

- decreased retail revenues related to reductions in retail electricity prices ($27 million).

Regulated electricity segment purchased power and fuel costs were $162 million higher in the year ended December 31, 2001 compared with the prior year as a result of:

- decreased costs related to other wholesale sales as a result of lower volumes ($29 million);
- higher replacement power costs primarily due to higher market prices and increased plant outages ($70 million), including costs of $12 million related to a Palo Verde outage extension to replace fuel control element assemblies;
- higher purchase power costs related to the 2001 generation reliability program ($30 million);
- higher costs related to retail sales volumes due to customer growth ($78 million); and
- charges related to purchased power contracts with Enron and its affiliates ($13 million).

**Marketing and Trading Segment Gross Margin**

Marketing and trading segment revenues were $154 million higher in the year ended December 31, 2001 compared with the prior year as a result of:

- increased revenues related to generation sales other than Native Load as a result of higher average market prices ($32 million);
- increased realized wholesale revenues net of related mark-to-market reversals primarily due to more transactions ($40 million);
- increased prior period mark-to-market value for losses transferred to realized margin in current period ($11 million); and
- increased mark-to-market value for future periods primarily as a result of more forward sales volumes ($71 million).

Marketing and trading segment purchased power and fuel costs were $47 million higher in the year ended December 31, 2001 compared with the prior year as a result of:

- increased fuel costs related to generation sales other than Native Load as a result of higher fuel prices ($7 million); and
- increased purchased power and fuel costs net of related mark-to-market reversals primarily due to more transactions ($40 million).

**Other Income Statement Items**

The increase in operations and maintenance expenses of $35 million primarily related to the 2001 generation reliability program (the addition of generating capability to enhance reliability for the summer of 2001) ($12 million) and increased employee benefit costs, plant outage and maintenance and other costs ($23 million).

Interest expense decreased by $15 million primarily because of lower interest rates and increased capitalized interest resulting from higher construction project balances.

Net other income increased $11 million primarily because of insurance recovery of environmental remediation costs (see Note 17).

See "Regulatory Matters – 1999 Settlement Agreement" in Note 3 for a discussion of the 1999 Settlement Agreement under which, among other things, we agreed to five annual retail electricity price reductions of 1.5%, with the last decrease to take effect July 1, 2003.

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Needs and Resources

#### Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the year ended December 31, 2002 and estimated capital expenditures for the next three years.

**CAPITAL EXPENDITURES**
(dollars in millions)

| | (Actual) | (Estimated) | | |
|---|---|---|---|---|
| | 2002 | 2003 | 2004 | 2005 |
| Delivery | $ 369 | $ 273 | $ 275 | $ 329 |
| Generation (a) | 132 | 123 | 99 | 164 |
| Other (b) | -- | 5 | 5 | 5 |
| Total | $ 501 | $ 401 | $ 379 | $ 498 |

(a) As discussed below under "Factors Affecting Our Financial Outlook," as part of our 2003 general rate case, we intend to seek rate base treatment of certain power plants currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3).

(b) The other amounts relate to capital expenditures for our marketing and trading segment. These costs were in the parent company for 2002.

Delivery capital expenditures are comprised of T&D infrastructure additions and upgrades, capital replacements, new customer construction and related information systems and facility costs. Examples of the types of projects included in the forecast include T&D lines and substations, line extensions to new residential and commercial developments and upgrades to customer information systems. In addition, we began several major transmission projects in 2001. These projects are periodic in nature and are driven by strong regional customer growth. We expect to spend about $105 million on major transmission projects during the 2003 to 2005 time frame, and these amounts are included in "Delivery" in the table above.

Generation capital expenditures are comprised of various improvements for our existing fossil and nuclear plants and the replacement of Palo Verde steam generators. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment such as turbines, boilers and environmental equipment. Generation also contains nuclear fuel expenditures of approximately $30 million annually for 2003 to 2005.

Replacement of the steam generators in Palo Verde Unit 2 is presently scheduled for completion during the fall outage of 2003. The Palo Verde owners have approved the manufacture of two additional sets of steam generators. We expect that these generators will be installed in Units 1 and 3 in the 2005 to 2008 time frame. Our portion of steam generator expenditures for Units 1, 2 and 3 is approximately $145 million, which will be spent from 2003 through 2008. In 2003 through 2005, $94 million of the costs are included in the generation capital expenditures table above and would be funded with internally-generated cash or external financings.

**Contractual Obligations**

Our capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "Factors Affecting Our Financial Outlook - Regulatory Matters" below and Note 3 for discussion of the $500 million financing arrangement between us and Pinnacle West Energy recently approved by the ACC. On November 22, 2002 the ACC approved our request (Interim Financing Application), to permit us to (a) make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of $125 million, or (b) guarantee $125 million of Pinnacle West's short-term debt, subject to certain conditions. As of December 31, 2002, there were no borrowings outstanding under the inter-affiliate financing arrangement. See the table below for our contractual requirements, including our debt repayment obligations. The table does not take into account any funds that we intend to lend to Pinnacle West Energy or Pinnacle West consistent with the foregoing financing arrangements.

We pay for our capital requirements with cash from operations and, to the extent necessary, external financings. We have historically paid for our dividends to Pinnacle West with cash from operations.

In 2002, we issued $375 million in long-term debt, refinanced $90 million in long-term debt and redeemed approximately $247 million in long-term debt (see Note 6). On April 7, 2003, we will redeem $33 million of our first mortgage bonds.

Our outstanding debt was approximately $2.2 billion at December 31, 2002. At December 31, 2002, we had credit commitments from various banks totaling about $250 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At December 31, 2002, we had no outstanding commercial paper or bank borrowings.

Although provisions in our first mortgage bond indenture, articles of incorporation and ACC financing orders establish maximum amounts of additional first mortgage bonds, debt and preferred stock that we may issue, we do not expect any of these provisions to limit our ability to meet our capital requirements.

We are part of a multi-employer pension plan sponsored by Pinnacle West. Pinnacle West contributes at least the minimum amount required under IRS regulations, but no more than the

maximum tax-deductible amount. The minimum required funding takes into consideration the value of the fund assets and the pension obligation. Pinnacle West elected to contribute cash to the pension plan in each of the last five years; the minimum required contributions during each of those years was zero. Specifically, Pinnacle West contributed $27 million for 2002, $24 million for 2001, $44 million for 2000, $25 million for 1999 and $14 million for 1998. We fund our share of the pension contribution. We represent approximately 90% of the total funding amounts described above. The assets in the plan are mostly domestic common stocks, bonds and real estate. Pinnacle West currently forecasts a pension contribution in 2003 of approximately $50 million, all or part of which may be required. If the fund performance continues to decline as a result of a continued decline in equity markets, larger contributions may be required in future years.

As a result of a change in IRS guidance, we claimed a tax deduction related to a tax accounting method change on the 2001 Pinnacle West federal consolidated income tax return. The accelerated deduction has resulted in a $200 million reduction in the current income tax liability. In 2002, we received an income tax refund of approximately $115 million related to the 2001 Pinnacle West federal consolidated income tax return.

The following table summarizes actual contractual requirements for the year ended December 31, 2002 and estimated contractual commitments for the next five years and thereafter (dollars in millions):

| | Actual | Estimated | | | | | |
|---|---|---|---|---|---|---|---|
| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | There-after |
| Long-term debt payments | $ 337 | $ -- | $ 205 | $ 400 | $ 84 | $ -- | $ 1,518 |
| Capital lease payments | -- | 4 | 3 | 3 | 3 | 2 | 5 |
| Operating lease payments | 60 | 59 | 59 | 59 | 59 | 59 | 456 |
| Fuel and purchase power commitments | 307 | 135 | 82 | 28 | 31 | 17 | 162 |
| Total contractual commitments | $ 704 | $ 198 | $ 349 | $ 490 | $ 177 | $ 78 | $ 2,141 |

**Off-Balance Sheet Arrangements**

In January 2003, the FASB issued FIN No. 46, "Consolidation of Variable Interest Entities." FIN No. 46 requires that we consolidate a VIE if we have a majority of the risk of loss from the VIE's activities or we are entitled to receive a majority of the VIE's residual returns or both. A VIE is a corporation, partnership, trust, or any other legal structure that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities. FIN No. 46 is effective immediately for any VIE created after January 31, 2003 and is effective July 1, 2003 for VIEs created before February 1, 2003.

In 1986, we entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 8 for further information about the sale-leaseback transactions. Based on our

preliminary assessment of FIN No. 46, we do not believe we will be required to consolidate the Palo Verde SPEs. However, we continue to evaluate the requirements of the new guidance to determine what impact, if any, it will have on our financial statements.

We are exposed to losses under the Palo Verde sale-leaseback agreements upon the occurrence of certain events that we do not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), we would be required to assume the debt associated with the transactions, make specified payments to the equity participants and take title to the leased Unit 2 interests, which if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2002, we would have been required to assume approximately $285 million of debt and pay the equity participants approximately $200 million.

**Credit Ratings**

The ratings of our securities as of March 28, 2003 are shown below and are considered "investment-grade" ratings. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies, if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of our securities and serve to increase our cost of and access to capital.

| | Moody's | Standard & Poor's | Fitch |
|---|---|---|---|
| Senior secured | A3 | A- | A- |
| Senior unsecured | Baa1 | BBB | BBB+ |
| Secured lease obligation bonds | Baa2 | BBB | BBB |
| Commercial paper | P-2 | A-2 | F-2 |

On November 4, 2002 Standard & Poor's affirmed our debt ratings in the above chart. On that same date, Standard & Poor's lowered our corporate credit rating from BBB+ to BBB. Standard & Poor's assigned a stable outlook to the ratings. All of our credit ratings remain investment grade. In December 2002, Fitch placed certain of our debt on Ratings Watch Negative. The ratings watch affects all of our debt ratings with the exception of our commercial paper rating.

On December 31, 2002, Moody's affirmed the ratings set forth above.

**Debt Provisions**

Our significant debt covenants include a debt-to-total-capitalization ratio and an interest coverage test. We are in compliance with such covenants and anticipate that we will continue to meet all the significant covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65%. At December 31, 2002, our ratio is approximately 48%. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements. The coverage is approximately 5 times for our bank agreements and 15 times for our mortgage indenture.

Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

Our financing agreements do not contain "ratings triggers" that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a ratings downgrade, we may be subject to increased interest costs under certain financing agreements.

All of our bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these bank agreements if we were to default under other agreements. Our credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in our financial condition or financial prospects.

## CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. We consider the following accounting policies to be our most critical because of uncertainties, judgments and complexities of the underlying accounting standards and operations involved.

- Regulatory Accounting – Regulatory accounting allows for the actions of regulators, such as the ACC and the FERC, to be reflected in the financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies.

- Pensions and Other Postretirement Benefit Accounting - Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term.

- Derivative Accounting – Derivative accounting requires evaluation of rules that are complex and subject to varying interpretations. Our evaluation of these rules, as they apply to our contracts, will determine whether we use accrual accounting or fair value (mark-to-market) accounting. Mark-to-market accounting requires that changes in fair value be recorded in earnings or, if certain hedge accounting criteria are met, in other comprehensive income.

- Mark-to-Market Accounting – The market value of our derivative contracts is not always readily determinable. In some cases, we use models and other valuation techniques to determine fair value. The use of these models and valuation techniques

sometimes requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods.

See the discussion below for further details on our critical accounting policies.

**Regulatory Accounting**

For our regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections of costs not likely to be incurred.

We are required to discontinue applying SFAS No. 71 when deregulatory legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated. In 1999, we discontinued the application of SFAS No. 71 for our generation operations due to the 1999 Settlement Agreement with the ACC. See Note 3 for a discussion of the 1999 Settlement Agreement.

In 2002, the ACC directed us not to transfer our generation assets, as previously required by the 1999 Settlement Agreement (see "Track A Order" in Note 3). Accordingly, we now consider our generation to be cost-based, rate-regulated and subject to the requirements of SFAS No. 71. The impact of this change was immaterial to our financial statements.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge to current period earnings. We had $241 million of regulatory assets included on the Balance Sheets at December 31, 2002. See Notes 1 and 3 for more information.

**Pensions and Other Postretirement Benefit Accounting**

Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for employees of Pinnacle West and its subsidiaries. In 2002, we represented 87% of the total costs of this plan. Our reported costs of providing defined pension and other postretirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension and other postretirement benefit costs, for example, are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the plans and earnings on plan assets. Changes made to the provisions of the plans may also impact current and future pension and other postretirement benefit costs. Pension and other postretirement benefit costs may also be significantly affected by changes in key actuarial assumptions, including the expected long-term rate

of return on plan assets and the discount rates used in determining the projected benefit obligation and pension and other postretirement benefit costs.

Pinnacle West's pension and other postretirement plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased pension and other postretirement benefit costs in future periods. Likewise, changes in assumptions regarding current discount rates and the expected long-term rate of return on plan assets could also increase or decrease recorded pension and other postretirement benefit costs.

We account for our defined benefit pension plans in accordance with SFAS No. 87, "Employers' Accounting for Pensions," which requires amounts recognized in our financial statements to be determined on an actuarial basis. Changes in pension obligations associated with these factors may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants.

The following chart reflects the sensitivities associated with a one percent increase or decrease in certain actuarial assumptions related to our defined benefit pension plans. Each sensitivity below reflects the impact of changing only that assumption. The chart shows the increase (decrease) each change in assumption would have on the 2002 Pinnacle West projected benefit obligation, the 2002 reported pension liability on the Pinnacle West Consolidated Balance Sheets and the 2002 reported annual pension expense, after consideration of amounts capitalized or billed to electric plant participants, on the Pinnacle West Consolidated Statements of Income (dollars in millions). In 2002, we represented 87% of the total cost of the plans.

| | Increase/(Decrease) | | |
|---|---|---|---|
| Actuarial Assumption | Impact on Projected Benefit Obligation | Impact on Pension Liability | Impact on Pension Expense |
| Discount rate: | | | |
| Increase 1% | $(143) | $(107) | $(4) |
| Decrease 1% | 177 | 130 | 9 |
| Expected long-term rate of return on plan assets: | | | |
| Increase 1% | - | - | (4) |
| Decrease 1% | - | - | 4 |

At the end of each year, we determine the discount rate to be used to calculate the present value of plan liabilities. The discount rate is an estimate of the current interest rate at which the pension liabilities could be effectively settled at the end of the year. The discount rate is selected by comparison to current yields on high-quality, long-term bonds. We changed our discount rate assumption from 7.5% at December 31, 2001 to 6.75% at December 31, 2002.

In 2002, we assumed that the expected long-term rate of return on plan assets would be 10%. However, the plan assets have earned a rate of return substantially less than 10% in the last three years due to sharp declines in the equity markets. For 2003, we decreased our expected long-term

rate of return on plan assets to 9%, as a result of continued declines in general equity and bond market returns.

The following chart reflects the sensitivities associated with a one percent increase or decrease in certain actuarial assumptions related to our other postretirement benefit plans. Each sensitivity below reflects the impact of changing only that assumption. The chart shows the increase (decrease) each change in assumption would have on the 2002 Pinnacle West accumulated other postretirement benefit obligation and the 2002 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on the Pinnacle West Consolidated Statements of Income (dollars in millions). In 2002, we represented 87% of the total cost of this plan.

| | Increase/(Decrease) | |
|---|---|---|
| Actuarial Assumption | Impact on Accumulated Postretirement Benefit Obligation | Impact on Other Postretirement Benefit Expense |
| Discount rate: | | |
| Increase 1% | $(38) | $(2) |
| Decrease 1% | 43 | 2 |
| Health care cost trend rate (a): | | |
| Increase 1% | 54 | 5 |
| Decrease 1% | (43) | (4) |
| Expected long-term rate of return on plan assets – pretax: | | |
| Increase 1% | - | (1) |
| Decrease 1% | - | 1 |

(a) This assumes a 1% change in the initial and ultimate health care cost trend rate.

The discount rate is selected by comparison to current yields on high-quality, long-term bonds. We changed our discount rate assumption from 7.5% at December 31, 2001 to 6.75% at December 31, 2002.

In selecting our health care cost trend rate, we consider past performance and forecasts of health care costs. In 2002, we increased our initial health care cost trend rate to 8% from 7% based on an analysis of our actual plan experience. We also assume an ultimate health care cost trend rate of 5% is reached in 2007.

In selecting the pretax expected long-term rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan. The market value of the plan assets has been affected by sharp declines in the equity markets. For 2003, we decreased our expected long-term rate of return on plan assets from 10% to 9%, as a result of continued declines in general equity and bond market returns.

Pension and other postretirement benefit costs and cash funding requirements may increase in future years without a substantial recovery in the equity markets. Due to the actual investment performance of the pension and other postretirement benefit funds and the changes in the actuarial

assumptions discussed above, we expect an increase of approximately $29 million before income taxes in 2003 expense over 2002. See Note 7 for further details about our pension and other postretirement benefit plans.

**Derivative Accounting**

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

We examine contracts at inception to determine the appropriate accounting treatment. If a contract does not meet the derivative criteria or if it qualifies for a SFAS No. 133 scope exception, we account for the contract on an accrual basis with associated revenues and costs recorded at the time the contracted commodities are delivered or received. SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard. Most of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered.

For contracts that qualify as a derivative and do not meet a SFAS No. 133 scope exception, we further examine the contract to determine if it will qualify for hedge accounting. Changes in the fair value of the effective portion of derivative instruments that qualify for cash flow hedge accounting treatment are recognized as either an asset or liability and in common stock equity (as a component of accumulated other comprehensive income (loss)). Gains and losses related to derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If a contract does not meet the hedging criteria in SFAS No. 133, we recognize the changes in the fair value of the derivative instrument in income each period through mark-to-market accounting.

On October 1, 2002, we adopted EITF 02-3, which rescinded EITF 98-10. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the accounting definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. See "Other Accounting Matters – Accounting for Derivative and Trading Activities" below for details on the change in accounting for energy trading contracts. See Note 16 for further discussion on derivative accounting.

**Mark-to-Market Accounting**

Under mark-to-market accounting, the purchase or sale of energy commodities is reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as assets and liabilities from risk management and trading activities in the Balance Sheets.

We determine fair market value using actively-quoted prices when available. We consider quotes for exchange-traded contracts and over-the-counter quotes obtained from independent brokers to be actively-quoted.

When actively-quoted prices are not available, we use prices provided by other external sources. This includes quarterly and calendar year quotes from independent brokers. We shape quarterly and calendar year quotes into monthly prices based on historical relationships.

For options, long-term contracts and other contracts for which price quotes are not available, we use models and other valuation methods. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices. The primary valuation technique we use to calculate the fair value of contracts where price quotes are not available is based on the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at the more illiquid delivery points. We also value option contracts using a variation of the Black-Scholes option-pricing model.

For non-exchange traded contracts, we calculate fair market value based on the average of the bid and offer price, and we discount to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks based on the financial condition of counterparties. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed-out or hedged.

A credit valuation adjustment is also recorded to represent estimated credit losses on our overall exposure to counterparties, taking into account netting arrangements; expected default experience for the credit rating of the counterparties; and the overall diversification of the portfolio. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of counterparties is based upon a number of factors, including credit ratings, financial condition, project economics and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. See "Factors Affecting Our Financial Outlook – Market Risks – Commodity Price Risk" below and Note 16 for further discussion on credit risk.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our practice is to hedge within timeframes established by the ERMC.

## OTHER ACCOUNTING MATTERS

### Accounting for Derivative and Trading Activities

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts, and on January 1, 2003 for existing contracts, with early adoption permitted. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. The impact of the guidance was immaterial to our financial statements.

EITF 02-3 requires derivatives held for trading purposes, whether settled financially or physically, be reported in the income statement on a net basis. Previous guidance under EITF 98-10 permitted physically settled energy trading contracts to be reported either gross or net in the income statement. Beginning in the third quarter of 2002, we netted all of our energy trading activities on the Statements of Income and restated prior year amounts for all periods presented. Reclassification of such trading activity to a net basis of reporting resulted in reductions in both revenues and purchased power and fuel costs, but did not have any impact on our financial condition, results of operations or cash flows.

In 2001, we adopted SFAS No. 133 and recorded a $15 million after-tax charge in net income and a $72 million after-tax credit in common stock equity (as a component of other comprehensive income), both as a cumulative effect of a change in accounting for derivatives. See Notes 1 and 16 for further information on accounting for derivatives under SFAS No. 133.

### Asset Retirement Obligations

On January 1, 2003 we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." The standard requires the fair value of asset retirement obligations to be recorded as a liability, along with an offsetting plant asset, when the obligation is incurred. Accretion of the liability due to the passage of time will be an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. (See Note 1 for more information regarding our previous accounting for removal costs.)

We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other generation, transmission and distribution assets. On January 1, 2003 we recorded a liability of $219 million for our asset retirement obligations including the accretion impacts; a $67 million increase in the carrying amount of the associated assets; and a net reduction of $192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, we recorded a regulatory liability of $40 million for our asset retirement obligations

related to our regulated utility. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. We believe we can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 143.

### Stock-Based Compensation

In the third quarter of 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123, "Accounting for Stock-Based Compensation." We recorded approximately $333,000 in stock option expense before income taxes in our Statements of Income for 2002. See Notes 1 and 14 for further information on the impacts of adopting the fair value method provided in SFAS No. 123.

### Variable Interest Entities

See "Liquidity and Capital Resources – Off-Balance Sheet Arrangements" and Note 18 for discussion of VIEs.

### Other

See Note 2 for discussion of other new accounting standards that are not expected to have a material impact on the Company.

## FACTORS AFFECTING OUR FINANCIAL OUTLOOK

### Regulatory Matters

#### General

On September 21, 1999, the ACC approved Rules that provide a framework for the introduction of retail electric competition in Arizona. On September 23, 1999, the ACC approved a comprehensive settlement agreement among us and various parties related to the implementation of retail electric competition in Arizona. Under the Rules, as modified by the 1999 Settlement Agreement, we were required to transfer all of our competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates no later than December 31, 2002. Consistent with that requirement, we had been addressing the legal and regulatory requirements necessary to complete the transfer of our generation assets to Pinnacle West Energy on or before that date. On September 10, 2002, the ACC issued the Track A Order, which, among other things, directed us not to transfer our generation assets to Pinnacle West Energy.

#### 1999 Settlement Agreement

The 1999 Settlement Agreement has affected, and will affect, our results of operations. As part of the 1999 Settlement Agreement, we agreed to reduce retail electricity prices for standard-offer, full-service customers with loads less than three megawatts in a series of annual decreases of 1.5% on July 1, 1999 through July 1, 2003, for a total of 7.5%. For customers with loads three megawatts or greater, standard-offer rates were reduced in annual increments totaling 5% in the years 1999 through 2002.

The 1999 Settlement Agreement also removed, as a regulatory disallowance, $234 million before income taxes ($183 million net present value) from ongoing regulatory cash flows. We recorded this regulatory disallowance as a net reduction of regulatory assets and reported it as a $140 million after-tax extraordinary charge on the 1999 Statement of Income. As discussed under "General Rate Case" below, we intend to seek recovery of this $234 million write-off in our next general rate case.

Prior to the 1999 Settlement Agreement, the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| $164 | $158 | $145 | $115 | $86 | $18 | $686 |

See Note 3 for additional information regarding the 1999 Settlement Agreement.

**Financing Application**

On September 16, 2002, we filed an application with the ACC requesting the ACC to allow us to borrow up to $500 million and to lend the proceeds to Pinnacle West Energy or to Pinnacle West; to guarantee up to $500 million of Pinnacle West Energy's or Pinnacle West's debt; or a combination of both, not to exceed $500 million in the aggregate. In our application, we stated that the ACC's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between us and Pinnacle West Energy under different regulatory regimes results in Pinnacle West Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing that Pinnacle West provided to fund the construction of Pinnacle West Energy generation assets or from effectively competing in the wholesale markets. On March 27, 2003, the ACC authorized APS to lend up to $500 million to Pinnacle West Energy, guarantee up to $500 million of Pinnacle West Energy debt, or a combination of both, not to exceed $500 million in the aggregate. See "ACC Applications" in Note 3 for further discussion of the approval and related conditions.

**Track A Order**

On September 10, 2002, the ACC issued the Track A Order. See "Track A Order" in Note 3.

**Competitive Procurement Process**

On September 10, 2002, the ACC issued an order that, among other things, established a requirement that we competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order, which documented the decision made by the ACC at its open meeting on February 27, 2003 addressing this requirement. Under the ACC's Track B Order, we will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, we will be required to solicit competitive bids for about 2,500

MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of our total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in our retail load and our retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets." The order recognizes our right to reject any bids that are unreasonable, uneconomical or unreliable.

We expect to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply our electricity requirements. See "Track B Order" in Note 3 for additional information.

**General Rate Case**

As required by the 1999 Settlement Agreement, on or before June 30, 2003, we will file a general rate case with the ACC. In this rate case, we will update our cost of service and rate design. In addition, we expect to seek:

- rate base treatment of certain power plants currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3);
- recovery of the $234 million pretax asset write-off recorded by us as part of the 1999 Settlement Agreement ($140 million extraordinary charge recorded on the 1999 Statement of Income); and
- recovery of costs incurred by us in preparation for the previously required transfer of generation assets to Pinnacle West Energy.

We assume that the ACC will make a decision in this general rate case by the end of 2004.

**Wholesale Power Market Conditions**

The marketing and trading division, which was moved to us in early 2003 for future marketing and trading activities (existing wholesale contracts will remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting our transfer of generating assets to Pinnacle West Energy, focuses primarily on managing our purchased power and fuel risks in connection with our costs of serving retail customer demand. Additionally, the marketing and trading division, subject to specified parameters, markets, hedges and trades in electricity, fuels and emission allowances and credits. Earnings contributions from Pinnacle West's marketing and trading division were lower in 2002 compared to 2001 due to weak wholesale power market conditions in the western United States, which included a lack of market liquidity, fewer creditworthy counterparties, lower wholesale market prices and resulting decreases in sales volumes. Our 2003 earnings will be affected by the strength (or weakness) of the wholesale power market.

**Factors Affecting Operating Revenues**

**General** Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona and from competitive retail and wholesale bulk power markets in the western

United States. These revenues are expected to be affected by electricity sales volumes related to customer mix, customer growth and average usage per customer as well as electricity prices and variations in weather from period to period.

**Customer Growth** Customer growth in our service territory averaged about 3.6% a year for the three years 2000 through 2002; we currently expect customer growth to average about 3.5 % per year from 2003 to 2005. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 5.5% a year in 2003 through 2005, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph applies to energy delivery customers. As previously noted, under the 1999 Settlement Agreement, we agreed to retail electricity price reductions of 1.5% annually through July 1, 2003 (see Note 3).

**Other Factors Affecting Future Financial Results**

**Purchased Power and Fuel Costs** Purchased power and fuel costs are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, prevailing market prices and our hedging program for managing such costs.

**Operations and Maintenance Expenses** Operations and maintenance expenses are expected to be affected by sales mix and volumes, power plant additions and operations, inflation, outages, higher trending pension and other postretirement benefit costs and other factors. In July 2002, we implemented a voluntary workforce reduction as part of our cost reduction program. We recorded $34 million before taxes in voluntary severance costs in the second half of 2002. In addition, we are expecting to produce annual operating expense savings of approximately $30 million beginning in 2003 as a result of this workforce reduction.

**Depreciation and Amortization Expenses** Depreciation and amortization expenses are expected to be affected by net additions to existing utility plant and other property and changes in regulatory asset amortization. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| $164 | $158 | $145 | $115 | $86 | $18 | $686 |

**Property Taxes** Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in-service and under construction. The average property tax rate was 9.7% of assessed value for 2002 and 9.3% for 2001. We expect property taxes to increase primarily due to our additions to existing facilities.

**Interest Expense** Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our capital requirements and our internally-generated cash flow. Capitalized interest offsets a portion of interest expense while capital projects are under construction. We stop recording capitalized interest on a project when it is placed in commercial operation. Interest expense is affected by interest rates on variable-rate debt. We are continuing to evaluate our construction program.

**Retail Competition** The regulatory developments and legal challenges to the Rules discussed in Note 3 have raised considerable uncertainty about the status and pace of retail electric competition in Arizona. Although some very limited retail competition existed in our service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to our customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter our service territory.

**General** Our financial results may be affected by a number of broad factors. See "Forward-Looking Statements" below for further information on such factors, which may cause our actual future results to differ from those we currently seek or anticipate.

## Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices and investments held by the nuclear decommissioning trust fund and the pension plans.

### Interest Rate and Equity Risk

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our pension plan (see Note 7) and nuclear decommissioning trust fund (see Note 11). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The pension plan and nuclear decommissioning fund also have risks associated with changing market values of equity investments. Pension and nuclear decommissioning costs are recovered in regulated electricity prices. See "Critical Accounting Policies – Pension and Other Postretirement Benefit Accounting" for a sensitivity analysis on the long-term rate of return on plan assets.

The tables below present contractual balances of our long-term debt and commercial paper at the expected maturity dates as well as the fair value of those instruments on December 31, 2002 and 2001. The interest rates presented in the tables below represent the weighted average interest rates for the years ended December 31, 2002 and 2001.

Expected Maturity/Principal Repayment
December 31, 2002
(dollars in thousands)

| | Short-Term Debt | | Variable-Rate Long-Term Debt | | Fixed-Rate Long-Term Debt | |
|---|---|---|---|---|---|---|
| | Interest Rates | Amount | Interest Rates | Amount | Interest Rates | Amount |
| 2003 | | $ -- | | $ -- | 5.86% | $ 3,503 |
| 2004 | | -- | | -- | 6.16% | 208,300 |
| 2005 | | -- | | -- | 7.27% | 403,300 |
| 2006 | | -- | | -- | 6.72% | 86,517 |
| 2007 | | -- | | -- | 5.78% | 2,227 |
| Years thereafter | | -- | 3.17% | 386,860 | 6.08% | 1,136,473 |
| Total | | $ -- | | $ 386,860 | | $ 1,840,320 |
| Fair Value | | $ -- | | $ 386,860 | | $ 1,937,244 |

Expected Maturity/Principal Repayment
December 31, 2001
(dollars in thousands)

| | Short-Term Debt | | Variable-Rate Long-Term Debt | | Fixed-Rate Long-Term Debt | |
|---|---|---|---|---|---|---|
| | Interest Rates | Amount | Interest Rates | Amount | Interest Rates | Amount |
| 2002 | 4.72% | $ 171,162 | | $ -- | 8.10% | $ 125,451 |
| 2003 | -- | -- | | -- | 6.18% | 337 |
| 2004 | -- | -- | | -- | 6.08% | 205,185 |
| 2005 | -- | -- | | -- | 7.59% | 400,185 |
| 2006 | -- | -- | | -- | 6.77% | 83,880 |
| Years thereafter | -- | -- | 2.60% | 476,860 | 6.73% | 787,894 |
| Total | | $ 171,162 | | $ 476,860 | | $ 1,602,932 |
| Fair Value | | $ 171,162 | | $ 476,860 | | $ 1,621,937 |

**Commodity Price Risk**

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. The ERMC, consisting of senior officers, oversees company-wide energy risk management activities and monitors the results of marketing and trading activities to ensure compliance with our stated energy risk management and trading policies. As part of our risk management program, we enter into

derivative transactions to hedge purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

Prior to October 1, 2002, we accounted for our energy trading contracts at fair value in accordance with EITF 98-10. On October 1, 2002, we adopted EITF 02-3, which rescinded EITF 98-10. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. See Note 16 for details on the change in accounting for energy trading contracts and further discussion regarding derivative accounting.

Both non-trading and trading derivatives are classified as assets and liabilities from risk management and trading activities in the Balance Sheets. For non-trading derivative instruments that qualify for hedge accounting treatment, changes in the fair value of the effective portion are recognized in common stock equity (as a component of accumulated other comprehensive income (loss)). Non-trading derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. Gains and losses related to non-trading derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If it becomes probable that a forecasted transaction will not occur, we discontinue the use of hedge accounting and recognize in income the unrealized gains and losses that were previously recorded in other comprehensive income (loss). In the event a non-trading derivative is terminated or settled, the unrealized gains and losses remain in other comprehensive income (loss), and are recognized in income when the underlying transaction impacts earnings.

Derivatives associated with trading activities are adjusted to fair value through income. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception and are not reflected on the balance sheet at fair value. Most of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered.

Our assets and liabilities from risk management and trading activities are presented in two categories consistent with our business segments:

- System - our regulated electricity business segment, which consists of non-trading derivative instruments that hedge our purchases and sales of electricity and fuel for our Native Load requirements; and

- Marketing and Trading - our non-regulated, competitive business segment, which includes both non-trading and trading derivative instruments.

The following tables show the changes in mark-to-market of our system and marketing and trading derivative positions in 2002 and 2001 (dollars in millions):

| | System | Marketing and Trading |
|---|---|---|
| Mark-to-market of net positions at December 31, 2001 | $ (107) | $ -- |
| Change in mark-to-market losses for future period deliveries | (22) | -- |
| Changes in cash flow hedges recorded in OCI | 64 | -- |
| Ineffective portion of changes in fair value recorded in earnings | 8 | -- |
| Mark-to-market losses realized during the year | 7 | -- |
| Mark-to-market of net positions at December 31, 2002 | $ (50) | $ -- |

| | System | Marketing and Trading |
|---|---|---|
| Mark-to-market of net positions at December 31, 2000 | $ -- | $ 12 |
| Cumulative effect adjustment due to adoption of SFAS No. 133 | 95 | -- |
| Change in mark-to-market (losses)/gains for future period deliveries | (12) | 85 |
| Changes in cash flow hedges recorded in OCI | (166) | -- |
| Ineffective portion of changes in fair value recorded in earnings | (6) | -- |
| Mark-to-market (gains)/losses realized during the year | (18) | 7 |
| Transfer of marketing and trading balance to Pinnacle West marketing and trading | -- | (104) |
| Mark-to-market of net positions at December 31, 2001 | $ (107) | $ -- |

As of December 31, 2002, a hypothetical adverse price movement of 10% in the market price of our risk management and trading assets and liabilities would have decreased the fair market value of these contracts by approximately $16 million, compared to a $23 million decrease that would have been realized as of December 31, 2001. A hypothetical favorable price movement of 10% would have increased the fair market value of these contracts by approximately $18 million, compared to a

$23 million increase that would have been realized as of December 31, 2001. These contracts are hedges of our forecasted purchases of natural gas. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged.

**Credit Risk**

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We use a risk management process to assess and monitor the financial exposure related to our counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See "Critical Accounting Policies - Mark-to-Market Accounting" above for a discussion of our credit valuation adjustment policy.

**Risk Factors**

Exhibit 99.3, which is hereby incorporated by reference, contains a discussion of risk factors affecting the Company.

**Forward-Looking Statements**

The above discussion contains forward-looking statements based on current expectations and we assume no obligation to update these statements or make any further statements on any of these issues, except as required by applicable laws. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including price caps and other market constraints imposed by the FERC; regional economic and market conditions, including the California energy situation and completion of generation construction in the region, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital and access to capital markets; weather variations affecting local and regional customer energy usage; the effect of conservation programs on energy usage; power plant performance; our ability to compete successfully outside traditional regulated markets (including the wholesale market); our ability to manage our marketing and trading activities and the use of derivative contracts in our business; technological developments in the electric industry; the performance of the stock market, which affects the amount of our required contributions to our pension plan and nuclear

decommissioning trust funds; and other uncertainties, all of which are difficult to predict and many of which are beyond our control.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Factors Affecting Our Financial Outlook - Market Risks" in Item 7 for a discussion of quantitative and qualitative disclosures about market risk.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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See Note 12 for the selected quarterly financial data required to be presented in this Item.

## INDEPENDENT AUDITORS' REPORT

To the Board of Directors and the Stockholder of
Arizona Public Service Company
Phoenix, Arizona

We have audited the accompanying balance sheets of Arizona Public Service Company (the "Company") as of December 31, 2002 and 2001, and the related statements of income, changes in common stock equity and cash flows for each of the three years in the period ended December 31, 2002. Our audits also included the financial statement schedule listed in the Index. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Arizona Public Service Company at December 31, 2002 and 2001, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 16 to the financial statements, in 2001 Arizona Public Service Company changed its method of accounting for derivatives and hedging activities in order to comply with the provisions of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona
February 3, 2003 (March 14, 26 and 27, 2003 as to Note 20)

## ARIZONA PUBLIC SERVICE COMPANY
## STATEMENTS OF INCOME

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Electric Operating Revenues: | | | |
| Regulated electricity segment | $ 2,059,339 | $ 2,562,088 | $ 2,538,750 |
| Marketing and trading segment | 34,054 | 549,240 | 395,392 |
| Total | 2,093,393 | 3,111,328 | 2,934,142 |
| Purchased Power and Fuel Costs: | | | |
| Regulated electricity segment | 595,368 | 1,227,188 | 1,065,596 |
| Marketing and trading segment | 32,662 | 313,991 | 267,032 |
| Total | 628,030 | 1,541,179 | 1,332,628 |
| Operating Revenues less Purchased Power and Fuel Costs | 1,465,363 | 1,570,149 | 1,601,514 |
| Other Operating Expenses: | | | |
| Operations and maintenance | 495,845 | 465,561 | 430,092 |
| Depreciation and amortization | 399,640 | 420,893 | 425,479 |
| Income taxes (Note 4) | 132,953 | 183,640 | 199,977 |
| Other taxes | 107,925 | 101,077 | 99,730 |
| Total | 1,136,363 | 1,171,171 | 1,155,278 |
| Operating Income | 329,000 | 398,978 | 446,236 |
| Other Income (Deductions): | | | |
| Other income (Note 17) | 5,149 | 20,207 | 9,690 |
| Other expense (Note 17) | (19,338) | (20,790) | (20,547) |
| Income taxes (Note 4) | 6,148 | 504 | 4,312 |
| Total | (8,041) | (79) | (6,545) |
| Income Before Interest Deduction | 320,959 | 398,899 | 439,691 |
| Interest Deductions: | | | |
| Interest on long-term debt | 128,462 | 126,118 | 134,431 |
| Interest on short-term borrowings | 5,416 | 4,407 | 7,455 |
| Debt discount, premium and expense | 2,888 | 2,650 | 2,105 |
| Capitalized interest | (15,150) | (14,964) | (10,894) |
| Total | 121,616 | 118,211 | 133,097 |
| Income Before Accounting Change | 199,343 | 280,688 | 306,594 |
| Cumulative Effect of Change in Accounting for Derivatives – net of income taxes of $9,892 | -- | (15,201) | -- |
| Net Income | $ 199,343 | $ 265,487 | $ 306,594 |

See Notes to Financial Statements.

## ARIZONA PUBLIC SERVICE COMPANY
## BALANCE SHEETS
## ASSETS

| | December 31, 2002 | December 31, 2001 |
|---|---|---|
| | (dollars in thousands) | |
| Utility Plant (Notes 1, 8 and 9) | | |
| Electric plant in service and held for future use | $ 8,299,131 | $ 7,935,206 |
| Less accumulated depreciation and amortization | 3,442,571 | 3,287,333 |
| Total | 4,856,560 | 4,647,873 |
| Construction work in progress | 329,089 | 321,305 |
| Intangible assets, net of accumulated amortization (Note 19) | 93,259 | 83,135 |
| Nuclear fuel, net of accumulated amortization of $102,821 and $99,185 | 7,466 | 6,933 |
| Utility Plant – net | 5,286,374 | 5,059,246 |
| Investments and Other Assets | | |
| Decommissioning trust accounts (Note 11) | 194,440 | 202,036 |
| Assets from risk management and trading activities – long-term | 31,622 | 2,082 |
| Other assets | 19,964 | 76,322 |
| Total Investments and Other Assets | 246,026 | 280,440 |
| Current Assets: | | |
| Cash and cash equivalents | 42,549 | 16,821 |
| Accounts receivable: | | |
| Service customers | 136,945 | 182,749 |
| Other (Note 1) | 202,597 | 55,016 |
| Allowance for doubtful accounts | (1,341) | (3,349) |
| Accrued utility revenues | 72,915 | 76,131 |
| Materials and supplies (at average cost) | 79,985 | 81,215 |
| Fossil fuel (at average cost) | 28,185 | 27,023 |
| Deferred income taxes (Note 4) | 4,094 | -- |
| Assets from risk management and trading activities | 39,616 | 10,097 |
| Other | 45,361 | 42,009 |
| Total Current Assets | 650,906 | 487,712 |
| Deferred Debits: | | |
| Regulatory assets (Notes 1 and 3) | 241,045 | 342,383 |
| Unamortized debt issue costs | 16,696 | 13,163 |
| Other | 80,760 | 42,789 |
| Total Deferred Debits | 338,501 | 398,335 |
| Total Assets | $ 6,521,807 | $ 6,225,733 |

See Notes to Financial Statements.

## ARIZONA PUBLIC SERVICE COMPANY
## BALANCE SHEETS
## LIABILITIES AND EQUITY

| | December 31, 2002 | December 31, 2001 |
|---|---|---|
| | (dollars in thousands) | |
| Capitalization: | | |
| Common stock | $ 178,162 | $ 178,162 |
| Additional paid-in capital | 1,246,804 | 1,246,804 |
| Retained earnings | 819,632 | 790,289 |
| Accumulated other comprehensive loss: | | |
| Minimum pension liability adjustment | (61,487) | (966) |
| Derivative instruments | (23,799) | (63,599) |
| Common stock equity | 2,159,312 | 2,150,690 |
| Long-term debt less current maturities (Note 6) | 2,217,340 | 1,949,074 |
| Total Capitalization | 4,376,652 | 4,099,764 |
| Current Liabilities: | | |
| Commercial paper (Note 5) | -- | 171,162 |
| Current maturities of long-term debt (Note 6) | 3,503 | 125,451 |
| Accounts payable | 118,133 | 98,959 |
| Accrued taxes | 82,557 | 107,595 |
| Accrued interest | 42,608 | 41,043 |
| Customer deposits | 39,865 | 28,664 |
| Deferred income taxes (Note 4) | -- | 3,244 |
| Liabilities from risk management and trading activities | 59,773 | 21,840 |
| Other | 51,820 | 18,798 |
| Total Current Liabilities | 398,259 | 616,756 |
| Deferred Credits and Other: | | |
| Deferred income taxes (Note 4) | 1,225,552 | 1,023,079 |
| Liabilities from risk management and trading activities | 36,678 | 95,159 |
| Unamortized gain – sale of utility plant (Note 8) | 59,484 | 64,060 |
| Customer advances for construction | 45,513 | 69,293 |
| Pension liability (Note 7) | 156,442 | 30,247 |
| Other | 223,227 | 227,375 |
| Total Deferred Credits and Other | 1,746,896 | 1,509,213 |
| Commitments and Contingencies (Notes 3, 10 and 11) | | |
| Total Liabilities and Equity | $ 6,521,807 | $ 6,225,733 |

See Notes to Financial Statements.

## ARIZONA PUBLIC SERVICE COMPANY
## STATEMENTS OF CASH FLOWS

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| | (dollars in thousands) | | |
| Cash Flows from Operating Activities: | | | |
| Net income | $ 199,343 | $ 265,487 | $ 306,594 |
| Items not requiring cash: | | | |
| Depreciation and amortization | 399,640 | 420,893 | 425,479 |
| Nuclear fuel amortization | 31,185 | 28,362 | 30,083 |
| Deferred income taxes | 206,767 | (26,516) | (65,726) |
| Change in mark-to-market | 2,957 | (100,030) | (11,752) |
| Cumulative effect of change in accounting – net of income taxes | -- | 15,201 | -- |
| Changes in certain current assets and liabilities: | | | |
| Accounts receivable | (102,450) | 302,283 | (209,705) |
| Materials, supplies and fossil fuel | 68 | (16,867) | 475 |
| Other current assets | (136) | (5,160) | (26,682) |
| Accounts payable | 15,372 | (190,141) | 101,558 |
| Accrued taxes | (25,038) | 1,080 | 43,657 |
| Accrued interest | 1,565 | 1,555 | 7,189 |
| Other current liabilities | 44,224 | (58,361) | 101,685 |
| Increase in regulatory assets | (11,029) | (17,516) | (14,138) |
| Change in risk management trading – assets | (22,570) | 10,730 | 13,181 |
| Change in customer advances | (23,780) | 28,599 | 2,544 |
| Change in pension liability | 5,415 | (30,346) | (18,373) |
| Change in other net long-term assets | (18,923) | (14,192) | 64,998 |
| Change in other net long-term liabilities | 1,902 | (9,986) | (27,396) |
| Net cash provided by operating activities | 704,512 | 605,075 | 723,671 |
| Cash Flows from Investing Activities: | | | |
| Capital expenditures | (490,156) | (465,360) | (464,368) |
| Capitalized interest | (15,150) | (14,964) | (10,894) |
| Other | 44,918 | (41,926) | (72,189) |
| Net cash used for investing activities | (460,388) | (522,250) | (547,451) |
| Cash Flows from Financing Activities: | | | |
| Issuance of long-term debt | 459,926 | 396,072 | 300,000 |
| Short-term borrowings | (171,162) | 89,062 | 43,800 |
| Dividends paid on common stock | (170,000) | (170,000) | (170,000) |
| Repayment and reacquisition of long-term debt | (337,160) | (383,747) | (354,888) |
| Net cash used for financing activities | (218,396) | (68,613) | (181,088) |
| Net increase (decrease) in cash and cash equivalents | 25,728 | 14,212 | (4,868) |
| Cash and cash equivalents at beginning of year | 16,821 | 2,609 | 7,477 |
| Cash and cash equivalents at end of year | $ 42,549 | $ 16,821 | $ 2,609 |
| Supplemental disclosure of cash flow information: | | | |
| Cash paid during the year for: | | | |
| Interest (excluding capitalized interest) | $ 117,081 | $ 114,094 | $ 123,895 |
| Income taxes paid/(refunded) (Note 4) | $ (54,283) | $ 212,989 | $ 222,866 |

See Notes to Financial Statements.

**ARIZONA PUBLIC SERVICE COMPANY**
**STATEMENTS OF CHANGES IN COMMON STOCK EQUITY**
For the Years Ended December 31, 2002, 2001 and 2000
(dollars in thousands)

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| COMMON STOCK | $ 178,162 | $ 178,162 | $ 178,162 |
| ADDITIONAL PAID-IN CAPITAL | 1,246,804 | 1,246,804 | 1,246,804 |
| RETAINED EARNINGS | | | |
| Balance at beginning of year | 790,289 | 694,802 | 558,208 |
| Net income | 199,343 | 265,487 | 306,594 |
| Common stock dividends | (170,000) | (170,000) | (170,000) |
| Balance at end of year | 819,632 | 790,289 | 694,802 |
| ACCUMULATED OTHER COMPREHENSIVE LOSS | | | |
| Balance at beginning of year | (64,565) | -- | -- |
| Minimum pension liability adjustment, net of tax of $39,696 and $634 | (60,521) | (966) | -- |
| Cumulative effect of a change in accounting for derivatives, net of tax of $47,404 in 2001 | -- | 72,274 | -- |
| Unrealized gain/(loss) on derivative instruments, net of tax of $25,426 and $71,720 | 38,764 | (109,346) | -- |
| Reclassification of realized (gain)/loss to income, net of tax of $679 and $17,399 | 1,036 | (26,527) | -- |
| Balance at end of year | (85,286) | (64,565) | -- |
| TOTAL COMMON STOCK EQUITY | $ 2,159,312 | $ 2,150,690 | $ 2,119,768 |
| COMPREHENSIVE INCOME | | | |
| Net income | $ 199,343 | $ 265,487 | $ 306,594 |
| Other comprehensive loss | (20,721) | (64,565) | -- |
| Comprehensive income | $ 178,622 | $ 200,922 | $ 306,594 |

See Notes to Financial Statements.

## 1. Summary of Significant Accounting Policies

### Nature of Operations

We are an electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about half of the Phoenix metropolitan area. Electricity is delivered through a distribution system owned by us. We also generate, sell and deliver electricity to wholesale customers in the western United States. In early 2003, the marketing and trading division was moved from Pinnacle West to us for future marketing and trading activities (existing wholesale contracts will remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of our generating assets to Pinnacle West Energy (see Note 3 for a discussion of the Track A Order). Our marketing and trading division sells, in the wholesale market, our and Pinnacle West Energy's generation output that is not needed for our Native Load, which includes loads for retail customers and cost-of-service wholesale customers. We do not distribute any products. Pinnacle West owns all of our outstanding stock.

During 2001, we transferred most of our marketing and trading activities to Pinnacle West, which approximated $219 million in assets and $149 million in liabilities. From time to time, we enter into transactions with Pinnacle West or Pinnacle West's subsidiaries. The following table summarizes the amounts included in the Statements of Income and Balance Sheets related to transactions with affiliated companies (dollars in millions):

| | For the year ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Electric operating revenues: | | | |
| Pinnacle West – marketing and trading | $ 85 | $ 50 | $ -- |
| APS Energy Services | -- | 15 | 26 |
| Total | $ 85 | $ 65 | $ 26 |
| Purchased power and fuel costs: | | | |
| Pinnacle West – marketing and trading | $ 135 | $ 50 | $ -- |
| Pinnacle West Energy | -- | 14 | -- |
| Total | $ 135 | $ 64 | $ -- |

| | As of December 31, | |
|---|---|---|
| | 2002 | 2001 |
| Net intercompany receivables/(payables): | | |
| Pinnacle West – marketing and trading | $ 135 | $ 13 |
| Pinnacle West | (1) | (11) |
| Pinnacle West Energy | (1) | 1 |
| APS Energy Services | -- | 13 |
| Total | $ 133 | $ 16 |

Electric revenues include sales of electricity to affiliated companies at contract prices. Purchased power includes purchases of electricity from affiliated companies at contract prices. Intercompany receivables primarily include the amounts related to the transfer of marketing and trading activities discussed above and intercompany sales of electricity. Intercompany payables primarily include amounts related to the purchase of electricity. Intercompany receivables and payables are generally settled on a current basis in cash.

**Accounting Records and Use of Estimates**

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. We have reclassified certain prior year amounts to conform to the current year presentation.

**Derivative Accounting**

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

We examine contracts at inception to determine the appropriate accounting treatment. If a contract does not meet the derivative criteria or if it qualifies for a SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," scope exception, we account for the contract on an accrual basis with associated revenues and costs recorded at the time the contracted commodities are delivered or received. SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard. Most of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered.

For contracts that qualify as a derivative and do not meet a SFAS No. 133 scope exception, we further examine the contract to determine if it will qualify for hedge accounting. Changes in the fair value of the effective portion of derivative instruments that qualify for cash flow hedge accounting treatment are recognized as either an asset or liability and in common stock equity (as a component of accumulated other comprehensive income (loss)). Gains and losses related to derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying

hedged physical transaction impacts earnings. If a contract does not meet the hedging criteria in SFAS No. 133, we recognize the changes in the fair value of the derivative instrument in income each period through mark-to-market accounting.

On October 1, 2002, we adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," which rescinded EITF 98-10. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. See Note 16 for more details on the change in accounting for energy trading contracts and for further discussion on derivative accounting.

**Mark-to-Market Accounting**

Under mark-to-market accounting, the purchase or sale of energy commodities is reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as assets and liabilities from risk management and trading activities in the Balance Sheets.

We determine fair market value using actively-quoted prices when available. We consider quotes for exchange-traded contracts and over-the-counter quotes obtained from independent brokers to be actively-quoted.

When actively-quoted prices are not available, we use prices provided by other external sources. This includes quarterly and calendar year quotes from independent brokers. We convert quarterly and calendar year quotes into monthly prices based on historical relationships.

For options, long-term contracts and other contracts for which price quotes are not available, we use models and other valuation methods. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices. The primary valuation technique we use to calculate the fair value of contracts where price quotes are not available is based on the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at the more illiquid delivery points. We also value option contracts using a variation of the Black-Scholes option-pricing model.

For non-exchange traded contracts, we calculate fair market value based on the average of the bid and offer price, and we discount to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks based on the financial condition of counterparties. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed-out or hedged.

A credit valuation adjustment is also recorded to represent estimated credit losses on our overall exposure to counterparties, taking into account netting arrangements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of counterparties is based upon a number of factors, including credit ratings, financial condition, project economics and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. See Note 16 for further discussion on credit risk.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our practice is to hedge within timeframes established by the ERMC.

**Regulatory Accounting**

We are regulated by the ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections of costs not likely to be incurred.

We are required to discontinue applying SFAS No. 71 when deregulatory legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated. In 1999, we discontinued the application of SFAS No. 71 for our generation operations due to the 1999 Settlement Agreement with the ACC. See Note 3 for a discussion of the 1999 Settlement Agreement.

As a result, we tested the generation assets for impairment and determined the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, a regulatory disallowance removed $234 million pretax ($183 million net present value) from ongoing regulatory cash flows and was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes) was reported as an extraordinary charge on the 1999 Statements of Income.

In 2002, the ACC directed us not to transfer our generation assets, as previously required by the 1999 Settlement Agreement (see "Track A Order" in Note 3). Accordingly, we now consider our generation to be cost-based, rate-regulated and subject to the requirements of SFAS No. 71. The impact of this change was immaterial to our financial statements.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

Prior to the 1999 Settlement Agreement, the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| $164 | $158 | $145 | $115 | $86 | $18 | $686 |

Regulatory assets are reported as deferred debits on the Balance Sheets. As of December 31, 2002 and 2001, they are comprised of the following (dollars in millions):

| | December 31, | |
|---|---|---|
| | 2002 | 2001 |
| Remaining balance recoverable under the 1999 Settlement Agreement (a) | $ 104 | $ 219 |
| Spent nuclear fuel storage (Note 10) | 46 | 43 |
| Electric industry restructuring transition costs (Note 3) | 40 | 34 |
| Other | 51 | 46 |
| Total regulatory assets | $ 241 | $ 342 |

(a) The majority of our unamortized regulatory assets above relates to deferred income taxes (see Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" below).

Regulatory liabilities are included in deferred credits and other on the Balance Sheets. As of December 31, 2002 and 2001, they are comprised of the following (dollars in millions):

| | December 31, | |
|---|---|---|
| | 2002 | 2001 |
| Deferred gains on utility property | $ 20 | $ 20 |
| Other | 6 | 7 |
| Total regulatory liabilities | $ 26 | $ 27 |

**Rate Synchronization Cost Deferrals**

As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). In accordance with the 1999 Settlement Agreement, we are continuing to accelerate the amortization of the deferrals over an eight-year period that will end June 30, 2004. Amortization of the deferrals is included in depreciation and amortization expense in the Statements of Income.

**Utility Plant and Depreciation**

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- construction overhead costs (where applicable); and
- capitalized interest or an allowance for funds used during construction.

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant, plus removal costs less salvage realized, to accumulated depreciation. See Note 2 for information on a new accounting standard that impacts accounting for removal costs.

We record depreciation on utility property on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2002 were as follows:

- Fossil plant – 20 years;
- Nuclear plant – 22 years
- Transmission – 34 years
- Distribution – 28 years; and
- Other utility property – 9 years

For the years 2000 through 2002 the depreciation rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 20%. The weighted-average rate was 3.35% for 2002, 3.40% for 2001 and 2000. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

**Capitalized Interest**

Capitalized interest represents the cost of debt funds used to finance construction projects. Plant construction costs, including capitalized interest, are expensed through depreciation when

completed projects are placed into commercial operation. Capitalized interest does not represent current cash earnings. The rate used to calculate capitalized interest was a composite rate of 5.28% for 2002, 6.26% for 2001 and 6.62% for 2000.

**Electric Revenues**

Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading and the corresponding unbilled revenue are estimated. We exclude sales taxes on electric revenues from both revenue and taxes other than income taxes. Other than revenues and purchased power costs related to energy trading activities, revenues are reported on a gross basis in our Statements of Income.

All gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis.

**Cash and Cash Equivalents**

For purposes of the Statements of Cash Flows, we consider all highly liquid debt instruments purchased with an initial maturity of three months or less to be cash equivalents.

**Nuclear Fuel**

We charge nuclear fuel to fuel expense by using the unit-of-production method. The unit-of-production method is an amortization method based on actual physical usage. We divide the cost of the fuel by the estimated number of thermal units we expect to produce with that fuel. We then multiply that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

We also charge nuclear fuel expense for the permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel, and it charges us $0.001 per kWh of nuclear generation. See Note 10 for information about spent nuclear fuel disposal and Note 11 for information on nuclear decommissioning costs.

**Income Taxes**

Income taxes are provided using the asset and liability approach prescribed by SFAS No. 109, "Accounting for Income Taxes." Pinnacle West files the federal income tax return on a consolidated basis and files the state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to us as though we filed a separate income tax return. Any difference between the aforementioned allocations and the consolidated (and unitary) income tax liability is attributed to Pinnacle West.

**Reacquired Debt Costs**

For debt related to the regulated portion of our business, we amortize those gains and losses incurred upon early retirement over the original remaining life of the debt. In accordance with the 1999 Settlement Agreement, we are continuing to accelerate reacquired debt costs over an eight-year period that will end June 30, 2004. All regulatory asset amortization is included in depreciation and amortization expense in the Statements of Income.

**Stock-Based Compensation**

Pinnacle West offers stock-based compensation plans for officers and key employees of our company. In 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123, "Accounting for Stock-Based Compensation." The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees."

The following chart compares our net income and stock compensation expense to what those items would have been if we had recorded stock compensation expense based on the fair value method for all stock grants through 2002 (dollars in thousands):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Net income: | | | |
| As reported | $ 199,343 | $ 265,487 | $ 306,594 |
| Pro forma (fair value method) | 198,381 | 263,905 | 305,745 |
| Stock compensation expense (net of tax): | | | |
| As reported | 200 | -- | -- |
| Pro forma (fair value method) | 962 | 1,582 | 849 |

In order to calculate the fair value of the 2002 stock option grants and the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Risk-free interest rate | 4.17% | 4.08% | 5.81% |
| Dividend yield | 4.17% | 3.70% | 3.48% |
| Volatility | 22.59% | 27.66% | 32.00% |
| Expected life (months) | 60 | 60 | 60 |

See Note 14 for further discussion about our stock compensation plans.

## 2. Accounting Matters

On January 1, 2003 we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." The standard requires the fair value of asset retirement obligations to be recorded as a liability, along with an offsetting plant asset, when the obligation is incurred. Accretion of the liability due to the passage of time will be an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. (See Note 1 for more information regarding our previous accounting for removal costs.)

We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other fossil generation, transmission and distribution assets. On January 1, 2003 we recorded a liability of $219 million for our asset retirement obligations including the accretion impacts; a $67 million increase in the carrying amount of the associated assets; and a net reduction of $192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, we recorded a net regulatory liability of $40 million for our asset retirement obligations related to our regulated utility. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. We believe we can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 143.

In November 2002, the EITF reached a consensus on EITF 00-21, "Revenue Arrangements with Multiple Deliverables." EITF 00-21 addresses certain aspects of the accounting by a vendor for arrangements under which it will perform multiple revenue-generating activities. EITF 00-21 specifically addresses how to determine whether an arrangement has identifiable, separable revenue-generating activities. EITF 00-21 does not address when the criteria for revenue recognition are met or provide guidance on the appropriate revenue recognition convention. EITF 00-21 is effective for revenue arrangements entered into after July 1, 2003. We are currently evaluating the impacts of this new guidance, but we do not believe it will have a material impact on our financial statements.

On January 1, 2002, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," and the accounting and reporting provisions for the disposal of a segment of a business. This standard did not impact our financial statements at adoption.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements Nos. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" which, among other things, supersedes previous guidance for reporting gains and losses from extinguishment of debt. This standard did not impact our financial statements at adoption.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or

disposal plan. The guidance will be applied to exit or disposal activities initiated after December 31, 2002. This standard did not impact our financial statements at adoption.

In 2001, the American Institute of Certified Public Accountants (AICPA) issued an exposure draft of a proposed Statement of Position (SOP), "Accounting for Certain Costs Related to Property, Plant, and Equipment." This proposed SOP would create a project timeline framework for capitalizing costs related to property, plant and equipment construction. It would require that property, plant and equipment assets be accounted for at the component level and require administrative and general costs incurred in support of capital projects to be expensed in the current period. In November 2002, the AICPA announced they would no longer issue general purpose SOPs. The work they have performed on the proposed SOP will be transitioned to the FASB staff. In February 2003, the FASB determined that the AICPA should continue their deliberations on certain aspects of the proposed SOP. We are waiting for further guidance from the FASB staff and the AICPA on the timing of the final guidance.

See the following Notes for other new accounting standards:

- Notes 1 and 14 for a new accounting standard (SFAS No. 148) related to stock-based compensation;
- Note 16 for a new EITF issue (EITF 02-3) related to accounting for energy trading contracts;
- Note 18 for a new interpretation (FIN No. 46) related to VIEs; and
- Note 19 for a new standard (SFAS No. 142) related to goodwill and intangible assets.

## 3. Regulatory Matters

### Electric Industry Restructuring

### State

**Overview** On September 21, 1999, the ACC approved Rules that provide a framework for the introduction of retail electric competition in Arizona. On September 23, 1999, the ACC approved a comprehensive settlement agreement among us and various parties related to the implementation of retail electric competition in Arizona. Under the Rules, as modified by the 1999 Settlement Agreement, we were required to transfer all of our competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates no later than December 31, 2002. Consistent with that requirement, we had been addressing the legal and regulatory requirements necessary to complete the transfer of our generation assets to Pinnacle West Energy on or before that date. On September 10, 2002, the ACC issued the Track A Order, which, among other things, directed us not to transfer our generation assets to Pinnacle West Energy. See "Track A Order" below.

On September 16, 2002, we filed an application with the ACC requesting the ACC to allow us to borrow up to $500 million and to lend the proceeds to Pinnacle West Energy or to Pinnacle West; to guarantee up to $500 million of Pinnacle West Energy's or Pinnacle West's debt; or a combination of both, not to exceed $500 million in the aggregate. In our application, we stated that

the ACC's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between us and Pinnacle West Energy under different regulatory regimes result in Pinnacle West Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing provided by Pinnacle West to fund the construction of Pinnacle West Energy generation assets or from effectively competing in the wholesale markets. On March 27, 2003, the ACC authorized us to lend up to $500 million to Pinnacle West Energy, guarantee up to $500 million of Pinnacle West Energy debt, or a combination of both, not to exceed $500 million in the aggregate. See "ACC Applications" below.

**Competitive Procurement Process**

On September 10, 2002, the ACC issued an order that, among other things, established a requirement that we competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order which documented the decision made by the ACC at its open meeting on February 27, 2003, addressing this requirement. Under the order, we will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, we will be required to solicit competitive bids for about 2,500 megawatts of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of our total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in our retail load and retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets." The order recognizes our right to reject any bids that are unreasonable, uneconomical or unreliable.

We expect to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply our electricity requirements. See "Track B Order" below.

These regulatory developments and legal challenges to the Rules have raised considerable uncertainty about the status and pace of retail electric competition in Arizona. These matters are discussed in more detail below.

**1999 Settlement Agreement**

The following are the major provisions of the 1999 Settlement Agreement, as approved by the ACC:

- We have reduced, and will reduce, rates for standard-offer service for customers with loads less than three MW in a series of annual retail electricity price reductions of 1.5% on July 1, for each of the years 1999 to 2003, for a total of 7.5%. Based on the price reductions authorized in the 1999 Settlement Agreement, there were retail price decreases of approximately $24 million ($14 million after taxes), effective July 1, 1999; approximately $28 million ($17 million after taxes), effective July 1, 2000; approximately $27 million ($16 million after taxes), effective July 1, 2001; and approximately $28 million ($17 million after taxes), effective July 1, 2002. The final price reduction is to be implemented July 1, 2003. For customers having loads of

three MW or greater, standard-offer rates have been reduced in varying annual increments that total 5% in the years 1999 through 2002.

- Unbundled rates being charged by us for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.

- There will be a moratorium on retail price changes for standard-offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor we will be prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms; material changes in our cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders.

- We will be permitted to defer for later recovery prudent and reasonable costs of complying with the Rules, system benefits costs in excess of the levels included in then-current (1999) rates, and costs associated with the "provider of last resort" and standard-offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004.

- Our distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the Rules (see "Retail Electric Competition Rules" below), including an additional 140 MW being made available to eligible non-residential customers. We opened our distribution system to retail access for all customers on January 1, 2001. The regulatory developments and legal challenges to the Rules discussed in this note have raised considerable uncertainty about the status and pace of electric competition in Arizona. Although some very limited retail competition existed in our service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to our customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter our service territory.

- Prior to the 1999 Settlement Agreement, we were recovering substantially all of our regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that we had demonstrated that our allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value (in 1999 dollars). We will not be allowed to recover $183 million net present value (in 1999 dollars) of the above amounts. The 1999 Settlement Agreement provides that we will have the opportunity to recover $350 million net present value (in 1999 dollars) through a competitive transition

charge that will remain in effect through December 31, 2004, at which time it will terminate. The costs subject to recovery under the adjustment clause described above will be decreased or increased by any over/under-recovery due to sales volume variances.

- We will form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) our competitive electric assets and services at book value as of the date of transfer, and will complete the transfers no later than December 31, 2002. We will be allowed to defer and later collect, beginning July 1, 2004, 67% percent of our costs to accomplish the required transfer of generation assets to an affiliate. However, as noted above and discussed in greater detail below, in 2002, the ACC unilaterally modified this aspect of the 1999 Settlement Agreement by issuing an order preventing us from transferring our generation assets.

**Retail Electric Competition Rules**

The Rules approved by the ACC included the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including us.

- Effective January 1, 2001, retail access became available to all of our retail electricity customers.

- Electric service providers that get CC&N's from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.

- Affected utilities must file ACC tariffs that unbundle rates for noncompetitive services.

- The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.

- Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates. Under the 1999 Settlement Agreement, we received a waiver to allow transfer of our competitive electric assets and services to affiliates no later than December 31, 2002. However, as noted above and discussed in greater detail below, in 2002, the ACC reversed its decision, as reflected in the Rules, to require us to transfer our generation assets.

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two

cannot be reconciled, we must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, to operate in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of our property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Arizona Court of Appeals, as a result of which the Superior Court's ruling is automatically stayed pending further judicial review. That appeal is still pending. In a similar appeal concerning the issuance of competitive telecommunications CC&N's, the Arizona Court of Appeals invalidated rates for competitive carriers due to the ACC's failure to establish a fair value rate base for such carriers. That decision was upheld by the Arizona Supreme Court.

**Provider of Last Resort Obligation**

Although the Rules allow retail customers to have access to competitive providers of energy and energy services, we are the "provider of last resort" for standard-offer, full-service customers under rates that have been approved by the ACC. These rates are established until at least July 1, 2004. The 1999 Settlement Agreement allows us to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms; material changes in our cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders. Energy prices in the western wholesale market vary and, during the course of the last two years, have been volatile. At various times, prices in the spot wholesale market have significantly exceeded the amount included in our current retail rates. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, we may need to purchase additional supplemental power in the wholesale spot market. Unless we are able to obtain an adjustment of our rates under the emergency provisions of the 1999 Settlement Agreement, there can be no assurance that we would be able to fully recover the costs of this power.

**Generic Docket**

In January 2002, the ACC opened a "generic" docket to "determine if changed circumstances require the [ACC] to take another look at electric restructuring in Arizona." In February 2002, the ACC docket relating to our October 2001 filing was consolidated with several other pending ACC dockets, including the generic docket. On May 2, 2002, the ACC issued a procedural order stating that hearings would begin on June 17, 2002 on various issues, including our planned divestiture of generation assets to Pinnacle West Energy and associated market and affiliate issues. The procedural order also stated that consideration of the competitive bidding process required by the Rules would proceed concurrently with the Track A issues.

**Track A Order**

On September 10, 2002, the ACC issued the Track A Order, which documents decisions made by the ACC at an open meeting on August 27, 2002. The major provisions of the Track A Order include, among other things:

Provisions related to the reversal of the generation asset transfer requirement:

- The ACC reversed its decision, as reflected in the Rules, to require us to transfer our generation assets either to an unrelated third party or to a separate corporate affiliate; and

- the ACC unilaterally modified the 1999 Settlement Agreement, which authorized the transfer of our generating assets, and directed us to cancel our activities to transfer our generation assets to Pinnacle West Energy.

Provisions related to the wholesale competitive energy procurement process (Track B issues):

- The ACC stayed indefinitely the requirement of the Rules that we acquire 100% of our energy needs for our standard offer customers from the competitive market, with at least 50% obtained through a competitive bid process;

- the ACC established a requirement that we competitively procure, at a minimum, any required power that we cannot produce from our existing assets in accordance with the ultimate outcome of the Track B proceedings;

- the ACC directed the parties to develop a competitive procurement ("bidding") process that can begin by March 1, 2003; and

- the ACC stated that "the [Pinnacle West Energy] generating assets that APS may acquire from [Pinnacle West Energy] shall not be counted as APS assets in determining the amount, timing and manner of the competitive solicitation" for Track B purposes, thereby bifurcating the regulatory treatment of our existing assets and the Pinnacle West Energy assets.

On November 15, 2002, we filed appeals of the Track A Order in the Maricopa County, Arizona Superior Court and in the Arizona Court of Appeals. Arizona Public Service Company v. Arizona Corporation Commission, CV2002-0222 32. Arizona Public Service Company v. Arizona Corporation Commission, 1CA CC 02-0002. On December 13, 2002, we and the ACC staff agreed to principles for resolving certain issues raised by us in our appeals of the Track A Order. We and the ACC are the only parties to the Track A Order appeals. The major provisions of this document include, among other things, the following:

- The parties agreed that it would be appropriate for the ACC to consider the following matters in our upcoming general rate case, anticipated to be filed before June 30, 2003:

- the generating assets to be included in our rate base, including the question of whether certain power plants currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5, and Saguaro Unit 3) should be included in our rate base;

- the appropriate treatment of the $234 million pretax asset write-off agreed to by us as part of a 1999 settlement agreement approved by the ACC among us and various parties related to the implementation of retail competition in Arizona; and

- the appropriate treatment of costs incurred by us in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy.

- Upon the ACC's issuance of a final decision that is no longer subject to appeal approving the Financing Application, with appropriate conditions, our appeals of the Track A Order would be limited to the issues described in the preceding bullet points, each of which would be presented to the ACC for consideration prior to any final judicial resolution.

On February 21, 2003, a Notice of Claim was filed with the ACC and the Arizona Attorney General on behalf of Pinnacle West, Pinnacle West Energy and us to preserve their and our rights relating to the Track A Order.

**Track B Order**

The ACC Staff has conducted workshops on the Track B issues with various parties to determine and define the appropriate process to be used for competitive power procurement. On September 10, 2002, the ACC issued an order that, among other things, established a requirement that APS competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order which documented the decision made by the ACC at its open meeting on February 27, 2003, addressing this requirement. The order adopted most of the provisions of an ACC ALJ's recommendation that was issued on January 30, 2003. Under the ACC's Track B Order, we will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, we will be required to solicit competitive bids for about 2,500 megawatts of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of our total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in our retail load and retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets."

The order recognizes our right to reject any bids that are unreasonable, uneconomical or unreliable. The Track B procurement process will involve the ACC Staff and an independent monitor. The Track B Order also contains requirements relating to standards of conduct between us and any of our affiliates that may participate in the competitive solicitation, requires that we treat bidders in a non-discriminatory manner and requires us to file a protocol regarding short-term and

emergency procurements. The order permits the provision of corporate oversight support and governance as long as such activities do not favor Pinnacle West Energy in the procurement process or provide Pinnacle West Energy with our confidential bidding information that is not available to other bidders. The order directs us to evaluate bids on cost, reliability and reasonableness. The decision requires bidders to allow the ACC to inspect their plants and requires assurances of appropriate competitive market conduct from senior officers of such bidders. Following the solicitation, we will prepare a report evaluating environmental issues relating to the procurement and a series of workshops on environmental risk management will be commenced thereafter.

We expect to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply our electricity requirements.

**ACC Applications**

On September 16, 2002, we filed a Financing Application requesting the ACC to allow us to borrow up to $500 million and to lend the proceeds to Pinnacle West Energy or Pinnacle West; to guarantee up to $500 million of Pinnacle West Energy's or Pinnacle West's debt; or a combination of both, not to exceed $500 million in the aggregate. The loan and/or the guarantee would be used to refinance debt incurred to fund the construction of Pinnacle West Energy generation assets.

The Financing Application addressed, among other things, the following matters:

- We noted that our April 19, 2002 filing with the ACC had sought unification of "[Pinnacle West Energy] Assets" (West Phoenix Units 4 and 5, Redhawk Units 1 and 2, and Saguaro Unit 3) and our generation assets under a common financial and regulatory regime. We further noted that the Track A Order's language regarding the treatment of the Pinnacle West Energy Assets for Track B purposes appears to postpone a decision regarding the inclusion of the Pinnacle West Energy Assets in our rate base, thereby effectively precluding the consolidation of the Pinnacle West Energy Assets at APS under a common financial and regulatory regime at the present time.

- We stated that we did not intend or desire to foreclose the possibility that we would acquire all or part of the Pinnacle West Energy Assets or that we may propose that the Pinnacle West Energy Assets be included in our rate base or afforded cost-of-service regulatory treatment to the extent the Pinnacle West Energy Assets are used by our customers. We stated that these issues would be appropriate topics in our 2003 general rate case and noted that the Track A Order specifically stated that the ACC would not pre-judge the eventual rate treatment of the Pinnacle West Energy Assets.

- We stated that the Track A Order's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between us and Pinnacle West Energy under different regulatory regimes result in Pinnacle West

Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing provided by Pinnacle West to fund the construction of the Pinnacle West Energy Assets or from effectively competing in the wholesale markets. We noted that Pinnacle West Energy had previously received investment-grade credit ratings contingent upon its receipt of our generation assets and that Pinnacle West's credit ratings could be adversely affected if Pinnacle West Energy is unable to finance its capital requirements. On November 4, 2002, Standard & Poor's lowered Pinnacle West's senior unsecured debt rating from "BBB" to "BBB-."

- We stated that the amount of the requested loan and/or guarantee is our present estimate of the amount of credit support necessary through us to restore Pinnacle West Energy and Pinnacle West to their credit status prior to the ACC's issuance of the Track A Order. We further stated that if the requested amount proves to be inadequate, we reserve the right to submit a second financing application seeking additional credit support.

On March 27, 2003, the ACC approved the Financing Application, subject to the following principal conditions:

- any debt issued by us pursuant to the order must be unsecured;
- we will be permitted to loan up to $500 million to Pinnacle West Energy (the "APS Loan"), guarantee up to $500 million of Pinnacle West Energy debt, or a combination of both, not to exceed $500 million in the aggregate;
- the APS Loan must be callable and secured by certain Pinnacle West Energy assets;
- the APS Loan must bear interest at a rate equal to 264 basis points above the interest rate on our debt that could be issued and sold on equivalent terms (including, but not limited to, maturity and security);
- the 264 basis points referred to in the previous bullet point will be capitalized as a deferred credit and used to offset retail rates in the future, with the deferred credit balance bearing an interest rate of six percent per annum;
- the APS Loan must have a maturity date of not more than four years, unless otherwise ordered by the ACC;
- any demonstrable increase in our cost of capital as a result of the transaction (such as from a decline in bond rating) will be excluded from future rate cases;
- we must maintain a common equity ratio of at least forty percent and may not pay common dividends if such payment would reduce our common equity ratio below that threshold, unless otherwise waived by the ACC. The ACC will process any

waiver request within sixty days, and for this sixty-day period this condition will be suspended. However, this condition, which will continue indefinitely, will not be permanently waived without an order of the ACC; and

- certain waivers of the ACC's affiliated interest rules previously granted to APS and its affiliates will be withdrawn and, during the term of the APS Loan, neither Pinnacle West nor Pinnacle West Energy may reorganize or restructure, acquire or divest assets, or form, buy or sell affiliates (each, a "Covered Transaction"), or pledge or otherwise encumber the Pinnacle West Energy assets without prior ACC approval, except that the foregoing restrictions will not apply to the following categories of Covered Transactions:

  - Covered Transactions less than $100 million, measured on a cumulative basis over the calendar year in which the Covered Transactions are made;

  - Covered Transactions by SunCor of less than $300 million through 2005, consistent with SunCor's anticipated accelerated asset sales activity during those years;

  - Covered Transactions related to the payment of ongoing construction costs for Pinnacle West Energy's (a) West Phoenix Unit 5, located in Phoenix, with an expected commercial operation date in mid-2003, and (b) Silverhawk plant, located near Las Vegas, with an expected commercial operation date in mid-2004; and

  - Covered Transactions related to the sale of 25% of the Silverhawk plant to Southern Nevada Water Authority if Southern Nevada Water Authority exercises its existing purchase option to do so.

The ACC also ordered the ACC staff to conduct an inquiry into our and our affiliates' compliance with the retail electric competition and related rules and decisions.

In mid-2003, Pinnacle West will need to refinance approximately $475 million of their indebtedness. We expect that this indebtedness will be repaid through funds borrowed by Pinnacle West Energy from us under the APS Loan.

On November 22, 2002, the ACC approved our request to permit us to (a) make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of $125 million or (b) guarantee $125 million of Pinnacle West's short-term debt, subject to certain conditions. See Note 5.

**Federal**

In July 2002, the FERC adopted a price mitigation plan that constrains the price of electricity in the wholesale spot electricity market in the western United States. The FERC has adopted a price

cap of $250 per MWh for the period subsequent to October 31, 2002. Sales at prices above the cap must be justified and are subject to potential refund.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking for Standard Market Design for wholesale electric markets. Voluminous comments and reply comments were filed on virtually every aspect of the proposed rule, and the FERC has announced that it will issue an additional white paper on the proposed Standard Market Design in April 2003. We are reviewing the proposed rulemaking and cannot currently predict what, if any, impact there may be to the Company if the FERC adopts the proposed rule or any modifications proposed in the comments.

**General**

The regulatory developments and legal challenges to the Rules discussed in this Note have raised considerable uncertainty about the status and pace of retail electric competition in Arizona. Although some very limited retail competition existed in our service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to our customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter our service territory. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete in the new regulatory environment.

## 4. Income Taxes

We are included in Pinnacle West's consolidated tax return. However, when Pinnacle West allocates income taxes to us, it does so based on our taxable income or loss alone.

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

We have recorded a regulatory asset related to income taxes on our Balance Sheets in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. We amortize this amount as the differences reverse. In accordance with ACC settlement agreements, we are continuing to accelerate amortization of a regulatory asset related to income taxes over an eight-year period that will end June 30, 2004 (see Note 1). Accordingly, we are including this accelerated amortization in depreciation and amortization expense on the Statements of Income.

As a result of a change in IRS guidance, we claimed a tax deduction related to a tax accounting method change on the 2001 Pinnacle West federal consolidated income tax return. The accelerated deduction has resulted in a $200 million reduction in the current income tax liability. In 2002, we received an income tax refund of approximately $115 million related to the 2001 Pinnacle West federal consolidated income tax return.

The components of income tax expense for income before accounting change are (dollars in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Current: | | | |
| Federal | $ (61,962) | $ 174,251 | $ 211,139 |
| State | (18,000) | 35,401 | 50,252 |
| Total current | (79,962) | 209,652 | 261,391 |
| Deferred | 206,767 | (26,516) | (65,726) |
| Total income tax expense | $ 126,805 | $ 183,136 | $ 195,665 |

The following table compares pretax income at the 35% federal income tax rate to income tax expense (dollars in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Federal income tax expense at 35% statutory rate | $ 114,152 | $ 162,338 | $ 175,791 |
| Increases (reductions) in tax expense resulting from: | | | |
| State income tax net of federal income tax benefit | 15,036 | 20,563 | 20,007 |
| Other | (2,383) | 235 | (133) |
| Income tax expense | $ 126,805 | $ 183,136 | $ 195,665 |

The following table sets forth the net deferred income tax liability recognized on the Balance Sheets at December 31, 2002 and 2001 (dollars in thousands):

| | December 31, | |
|---|---|---|
| | 2002 | 2001 |
| Current asset/(liability) | $ 4,094 | $ (3,244) |
| Long term liability | (1,225,552) | (1,023,079) |
| Accumulated deferred income taxes – net | $ (1,221,458) | $ (1,026,323) |

The components of the net deferred income tax liability were as follows (dollars in thousands):

| | December 31, | |
|---|---|---|
| | 2002 | 2001 |
| DEFERRED TAX ASSETS | | |
| Pension liability | $ 61,966 | $ 13,450 |
| Risk management and trading activities | 38,204 | 46,343 |
| Deferred gain on Palo Verde Unit 2 sale-leaseback | 23,562 | 25,374 |
| Other | 80,965 | 97,868 |
| Total deferred tax assets | 204,697 | 183,035 |
| DEFERRED TAX LIABILITIES | | |
| Plant-related | (1,316,636) | (1,069,207) |
| Regulatory asset for income taxes | (80,635) | (121,757) |
| Risk management and trading activities | (28,884) | (18,394) |
| Total deferred tax liabilities | (1,426,155) | (1,209,358) |
| Accumulated deferred income taxes – net | $ (1,221,458) | $ (1,026,323) |

## 5. Lines of Credit and Short-Term Borrowings

We had committed lines of credit with various banks of $250 million at December 31, 2002 and 2001, which were available either to support the issuance of commercial paper or to be used for bank borrowings. These lines of credit mature in June 2003. The commitment fees at December 31, 2002 and 2001 for these lines of credit were 0.09% per annum. We had no bank borrowings outstanding under these lines of credit at December 31, 2002 and 2001.

We had no commercial paper borrowings outstanding at December 31, 2002 and $171 million at December 31, 2001. The weighted average interest rate on commercial paper borrowings was 2.47% for the year ended December 31, 2002 and 4.72% for the year ended December 31, 2001. By Arizona statute, our short-term borrowings cannot exceed 7% of our total capitalization unless approved by the ACC.

On November 22, 2002, the ACC approved our request to permit us to (a) make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of $125 million, or (b) guarantee $125 million of Pinnacle West's short-term debt, subject to certain conditions. This interim loan matures in December 2003. There have been no borrowings on this line.

## 6. Long-Term Debt

Borrowings under our mortgage bond indenture are secured by substantially all of the Company's utility plant. We also have unsecured debt. The following table presents the components of long-term debt on the Balance Sheets outstanding at December 31, 2002 and 2001 (dollars in thousands):

| | Maturity Dates (a) | Interest Rates | December 31, 2002 | December 31, 2001 |
|---|---|---|---|---|
| First mortgage bonds | 2002 | 8.125% (b) | $ -- | $ 125,000 |
| | 2004 | 6.625% | 80,000 | 80,000 |
| | 2023 | 7.25% | 54,150 | 54,150 |
| | 2024 | 8.75% (c) | -- | 121,668 |
| | 2025 | 8.0% | 33,075 | 33,075 |
| | 2028 | 5.5% | 25,000 | 25,000 |
| | 2028 | 5.875% | 154,000 | 154,000 |
| Unamortized discount and premium | | | (6,337) | (5,266) |
| Pollution control bonds | 2024-2034 | (d) | 386,860 | 386,860 |
| Pollution control bonds | 2029 | 3.30% (e) | -- | 90,000 |
| Pollution control bonds with senior notes (f) | 2029 | 5.05% | 90,000 | -- |
| Unsecured notes | 2004 | 5.875% | 125,000 | 125,000 |
| Unsecured notes | 2005 | 6.25% | 100,000 | 100,000 |
| Unsecured notes | 2005 | 7.625% | 300,000 | 300,000 |
| Unsecured notes | 2011 | 6.375% | 400,000 | 400,000 |
| Unsecured notes | 2012 | 6.50% | 375,000 | -- |
| Senior notes (g) | 2006 | 6.75% | 83,695 | 83,695 |
| Capitalized lease obligations | 2003-2012 | 5.78% | 20,400 | 1,343 |
| Total long-term debt | | | 2,220,843 | 2,074,525 |
| Less current maturities | | | 3,503 | 125,451 |
| Total long-term debt less current maturities | | | $ 2,217,340 | $ 1,949,074 |

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.

(b) On March 15, 2002, we redeemed at maturity, $125 million of our First Mortgage Bonds, 8.125% Series due 2002.

(c) On April 15, 2002, we redeemed $122 million of our First Mortgage Bonds, 8.75% Series due 2024.

(d) The weighted-average rate was 1.94% at December 31, 2002 and 2.55% at December 31, 2001. Changes in short-term interest rates would affect the costs associated with this debt.

(e) In November 2001, these bonds were converted to a one year fixed rate of 3.30%. These bonds were previously adjustable rate, and from January 1, 2001 until October 31, 2001, the weighted average rate was 2.72%.

(f) On November 1, 2002, Maricopa County, Arizona Pollution Control Corporation issued $90 million of 5.05% Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Palo Verde Project) 2002 Series A, due 2029, and loaned the proceeds to us pursuant to a loan agreement. The bonds were issued to refinance $90 million of outstanding pollution control bonds. The bondholders were issued $90 million of first mortgage bonds (senior note mortgage bonds) as collateral.

(g) We currently have outstanding $84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes, as well as, the $90 million issue discussed in footnote (f) above. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity and redemption provisions as the senior notes. Our payments of principal, premium and/or interest on the senior notes satisfy our corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. When we repay all of our first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.

Our significant debt covenants related to our financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. We are in compliance with such covenants and anticipate that we will continue to meet all the significant covenant requirement levels. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

Our financing agreements do not contain "ratings triggers" that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a ratings downgrade, we may be subject to increased interest costs under certain financing agreements.

All of our bank agreements contain "cross-default" provisions under which a default by us in a specified amount under another agreement would result in a default and the potential acceleration of payment under the agreements. Our credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in the borrower's business or financial condition.

The following is a list of payments due on total long-term debt and capitalized lease requirements through 2007:

- $ 4 million in 2003;
- $ 208 million in 2004;
- $ 403 million in 2005;
- $ 87 million in 2006;
- $ 2 million in 2007; and
- $1,523 million, thereafter.

Our first mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment and other excluded assets). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. We may pay dividends on our common stock if there is a sufficient amount "available" from retained earnings and the excess of cumulative book depreciation (since the mortgage's inception) over mortgage depreciation, which is the cumulative amount of additional property pledged each year to address collateral depreciation. As of December 31, 2002, the amount "available" under the mortgage would have

allowed us to pay approximately $3 billion of dividends compared to our current annual common stock dividends of $170 million.

## 7. Retirement Plans and Other Benefits

### Pension Plans

Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and its subsidiaries. Effective January 1, 2003, Pinnacle West sponsored a new account balance pension plan for all new employees in place of the defined benefit plan, and, effective April 1, 2003, the new plan will be offered as an alternative to the defined benefit plan for all existing employees. In 2002, we represented 87% of the total cost of this plan. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all of our employees. The supplemental excess benefit plan covers officers of the company and highly compensated employees designated for participation by Pinnacle West's Board of Directors. Our employees do not contribute to the plans. Generally, the benefits under these plans are calculated based on age, years of service and pay. Pinnacle West funds the qualified plan by contributing at least the minimum amount required under IRS regulations but no more than the maximum tax-deductible amount. The assets in the qualified plan at December 31, 2002 were mostly domestic common stocks and bonds and real estate.

The following table shows our contributions and pension expense, including administrative costs, and after consideration of amounts capitalized or billed to electric plant participants for 2002, 2001, and 2000 (dollars in millions):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Contributions | $ 26 | $ 44 | $ 23 |
| Pension expense | $ 11 | $ 6 | $ 2 |

The following table shows the components of Pinnacle West's consolidated net periodic pension cost before consideration of amounts capitalized or billed to electric plant participants for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Service cost – benefits earned during the period | $ 30,333 | $ 27,640 | $ 26,040 |
| Interest cost on projected benefit obligation | 71,242 | 66,549 | 61,625 |
| Expected return on plan assets | (75,652) | (77,340) | (77,231) |
| Amortization of: | | | |
| Transition asset | (3,227) | (3,227) | (3,227) |
| Prior service cost | 2,912 | 3,008 | 2,370 |
| Net actuarial loss/(gain) | 1,846 | 907 | (1,190) |
| Net periodic pension cost | $ 27,454 | $ 17,537 | $ 8,387 |

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in Pinnacle West's Consolidated Balance Sheets at December 31, 2002 and 2001 (dollars in thousands):

| | 2002 | 2001 |
|---|---|---|
| Funded status – pension plan assets less than projected benefit obligation | $ (348,770) | $ (166,773) |
| Unrecognized net transition asset | (10,327) | (13,554) |
| Unrecognized prior service cost | 23,148 | 26,170 |
| Unrecognized net actuarial losses | 293,223 | 108,422 |
| Accrued pension benefit liability recognized in the Consolidated Balance Sheets | $ (42,726) | $ (45,735) |

The following table sets forth Pinnacle West's defined benefit pension plans' change in projected benefit obligation for the plan years 2002 and 2001 (dollars in thousands):

| | 2002 | 2001 |
|---|---|---|
| Projected pension benefit obligation at beginning of year | $ 931,646 | $ 840,485 |
| Service cost | 30,333 | 27,640 |
| Interest cost | 71,242 | 66,549 |
| Benefit payments | (35,230) | (33,282) |
| Actuarial losses | 71,696 | 21,632 |
| Plan amendments | (110) | 8,622 |
| Projected pension benefit obligation at end of year | $ 1,069,577 | $ 931,646 |

The following table sets forth Pinnacle West's qualified defined benefit pension plans' change in the fair value of plan assets for the plan years 2002 and 2001 (dollars in thousands):

| | 2002 | 2001 |
|---|---|---|
| Fair value of pension plan assets at beginning of year | $ 764,873 | $ 775,196 |
| Actual loss on plan assets | (36,966) | (22,876) |
| Employer contributions | 26,600 | 44,200 |
| Benefit payments | (33,700) | (31,647) |
| Fair value of pension plan assets at end of year | $ 720,807 | $ 764,873 |

The following table sets forth Pinnacle West's defined benefit pension plans' amounts recognized in Pinnacle West's Consolidated Balance Sheets at December 31, 2002 and 2001 (dollars in thousands):

| | 2002 | 2001 |
|---|---|---|
| Accrued pension benefit liability | $ (42,726) | $ (45,735) |
| Additional minimum liability | (141,155) | (3,297) |
| Intangible asset | 23,148 | 1,697 |
| Accumulated other comprehensive loss – pretax | 118,007 | 1,600 |

The following table shows Pinnacle West's accumulated benefit obligation in relation to the fair value of plan assets for the plan years 2002 and 2001 (dollars in thousands):

| | 2002 | 2001 |
|---|---|---|
| Projected benefit obligation | $ 1,069,577 | $ 931,646 |
| Accumulated benefit obligation | 904,687 | 752,230 |
| Fair value of plan assets | 720,807 | 764,873 |

The following are weighted-average assumptions as of December 31, 2002 and 2001:

| | 2002 | 2001 |
|---|---|---|
| Discount rate | 6.75% | 7.50% |
| Rate of increase in compensation levels | 4.00% | 4.00% |
| Expected long-term rate of return on assets | 9.00% | 10.00% |

**Employee Savings Plan Benefits**

Pinnacle West sponsors a defined contribution savings plan for the employees of Pinnacle West and its subsidiaries. In 2002, we represented 93% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant will receive result from regular contributions they make to a participant account. Under this plan, Pinnacle West makes matching contributions in Pinnacle West stock to participant accounts. After a five-year vesting period, participants have a choice to change the employer contribution match to other investments. At December 31, 2002,

approximately 25% of total plan assets were in Pinnacle West stock. We recorded expenses for this plan of approximately $4 million for 2002, $4 million for 2001, and $3 million for 2000.

**Other Postretirement Benefits**

Pinnacle West sponsors other postretirement benefits for the employees of Pinnacle West and its subsidiaries. In 2002, we represented 87% of the total cost of this plan. We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

Funding is based upon actuarially determined contributions that take tax consequences into account. Plan assets consist primarily of domestic stocks and bonds.

The following table shows our contributions and postretirement benefit expense after consideration of amounts capitalized or billed to electric plant participants for 2002, 2001 and 2000 (dollars in millions):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Contributions | $ 7 | $ 11 | $ 5 |
| Other postretirement benefit expense | $ 9 | $ 6 | $ 2 |

The following table shows the components of Pinnacle West's net periodic other postretirement benefit costs before consideration of amounts capitalized or billed to electric plant participants for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Service cost – benefits earned during the period | $ 12,036 | $ 9,438 | $ 8,613 |
| Interest cost on accumulated benefit obligation | 25,235 | 21,585 | 19,315 |
| Expected return on plan assets | (21,116) | (21,985) | (22,381) |
| Amortization of: | | | |
| Transition obligation | 4,001 | 7,698 | 7,698 |
| Prior service credit | (75) | -- | -- |
| Net actuarial loss/(gain) | 3,072 | (4,066) | (7,983) |
| Net periodic other postretirement benefit cost | $ 23,153 | $ 12,670 | $ 5,262 |

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in Pinnacle West's Consolidated Balance Sheets as of December 31, 2002 and 2001 (dollars in thousands):

| | 2002 | 2001 |
|---|---|---|
| Funded status – other postretirement plan assets less than accumulated other postretirement benefit obligation | $ (186,400) | $ (80,544) |
| Unrecognized net obligation at transition | 36,489 | 84,748 |
| Unrecognized prior service credit | (1,673) | -- |
| Unrecognized net actuarial loss/(gain) | 148,268 | (8,606) |
| Net other postretirement benefit liability recognized in the Consolidated Balance Sheets | $ (3,316) | $ (4,402) |

The following table sets forth Pinnacle West's other postretirement benefit plan's change in accumulated postretirement benefit obligation for the plan years 2002 and 2001 (dollars in thousands):

| | 2002 | 2001 |
|---|---|---|
| Accumulated other postretirement benefit obligation at beginning of year | $ 318,355 | $ 264,006 |
| Service cost | 12,036 | 9,438 |
| Interest cost | 25,235 | 21,585 |
| Benefit payments | (10,473) | (10,194) |
| Actuarial losses | 108,979 | 33,520 |
| Plan amendments | (44,258) (a) | -- |
| Accumulated other postretirement benefit obligation at end of year | $ 409,874 | $ 318,355 |

(a) The plan was amended January 1, 2002 to increase the deductibles, out of pocket maximums and prescription drug co-pays. The plan was amended in June 2002 to increase the participants' portion of premiums.

The following table sets forth Pinnacle West's other postretirement benefit plan's change in the fair value of plan assets for the plan years 2002 and 2001 (dollars in thousands):

| | 2002 | 2001 |
|---|---|---|
| Fair value of other postretirement benefit plan assets at beginning of year | $ 237,810 | $ 249,154 |
| Actual loss on plan assets | (27,802) | (12,550) |
| Employer contributions | 23,600 | 11,400 |
| Benefit payments | (10,134) | (10,194) |
| Fair value of other postretirement benefit plan assets at end of year | $ 223,474 | $ 237,810 |

The following are weighted-average assumptions as of December 31, 2002 and 2001:

| | 2002 | 2001 |
|---|---|---|
| Discount rate | 6.75% | 7.50% |
| Expected long-term rate of return on assets – pretax | 9.00% | 10.00% |
| Expected long-term rate of return on assets – after tax | 7.84% | 8.71% |
| Initial health care cost trend rate – under age 65 | 8.00% | 7.00% |
| Initial health care cost trend rate – age 65 and over | 8.00% | 7.00% |
| Ultimate health care cost trend rate | 5.00% | 5.00% |
| Year ultimate health care trend rate is reached | 2007 | 2006 |

The following table shows the effect of a 1% increase or decrease in the initial and ultimate health care expense and cost trend rate (dollars in millions):

| | 1% increase | 1% decrease |
|---|---|---|
| Effect of the 2002 other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants | $ 5 | $ (4) |
| Effect on the 2002 service and interest cost components of net periodic other postretirement benefit costs | 7 | (6) |
| Effect on the accumulated other postretirement benefit obligation at December 31, 2002 | 54 | (43) |

**Severance Charges**

In July 2002, we implemented a voluntary workforce reduction as part of our cost reduction program. We recorded $34 million before taxes in voluntary severance costs in 2002. No further charges are expected.

## 8. Leases

In 1986, we sold about 42% of our share of Palo Verde Unit 2 and certain common facilities in three separate sale-leaseback transactions. We account for these leases as operating leases. The gain resulting from the transaction of approximately $140 million was deferred and is being amortized to operations and maintenance expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Consistent with the ratemaking treatment, a regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis. See Note 18 for a discussion of VIEs, including the SPEs involved in the Palo Verde sale-leaseback transactions.

In addition, we lease certain land, buildings, equipment, vehicles and miscellaneous other items through operating rental agreements with varying terms, provisions and expiration dates.

Total lease expense recognized in the Statements of Income was $52 million in 2002, $52 million in 2001 and $53 million in 2000.

The amounts to be paid for the Palo Verde Unit 2 leases are approximately $49 million per year for the years 2003 to 2015.

In accordance with the 1999 Settlement Agreement and previous settlement agreements, we are continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004 (see Note 1). All regulatory asset amortization is included in depreciation and amortization expense in the Statements of Income. The balance of this regulatory asset at December 31, 2002 was $14 million.

Estimated future minimum lease payments for our operating leases are approximately $59 million for each of the years 2003 to 2007 and $456 million thereafter.

## 9. Jointly-Owned Facilities

We share ownership of some of our generating and transmission facilities with other companies. The following table shows our interest in those jointly-owned facilities recorded on the Balance Sheets at December 31, 2002. Our share of operating and maintaining these facilities is included in the Statements of Income in operations and maintenance expense.

| | Percent Owned by APS | Plant in Service | Accumulated Depreciation | Construction Work in Progress |
|---|---|---|---|---|
| | | (dollars in thousands) | | |
| Generating facilities: | | | | |
| Palo Verde Nuclear Generating Station Units 1 and 3 | 29.1% | $1,829,225 | $(905,278) | $17,428 |
| Palo Verde Nuclear Generating Station Unit 2 (see Note 8) | 17.0% | 574,745 | (289,049) | 68,475 |
| Four Corners Steam Generating Station Units 4 and 5 | 15.0% | 153,559 | (82,434) | 500 |
| Navajo Steam Generating Station Units 1, 2 and 3 | 14.0% | 235,743 | (110,923) | 3,010 |
| Cholla Steam Generating Station Common Facilities (a) | 62.8%(b) | 76,322 | (42,608) | 1,733 |
| Transmission facilities: | | | | |
| ANPP 500KV System | 35.8%(b) | 68,314 | (25,655) | 31 |
| Navajo Southern System | 31.4%(b) | 27,129 | (17,405) | 664 |
| Palo Verde-Yuma 500KV System | 23.9%(b) | 9,591 | (4,168) | 383 |
| Four Corners Switchyards | 27.5%(b) | 3,071 | (1,979) | -- |
| Phoenix-Mead System | 17.1%(b) | 36,418 | (2,906) | -- |
| Palo Verde – Estrella 500KV System | 50.0%(b) | -- | -- | 50,450 |

(a) PacifiCorp owns Cholla Unit 4 and we operate the unit for PacifiCorp. The common facilities at the Cholla Plant are jointly-owned.

(b) Weighted average of interests.

## 10. Commitments and Contingencies

### Enron

We recorded charges totaling $13 million before income taxes for exposure to Enron and its affiliates in the fourth quarter of 2001. These charges take into consideration our rights of set-off with respect to the Enron related contractual obligations. The basis of the set-offs included, but was not limited to, provisions in the various contractual arrangements with Enron and its affiliates, including an International Swaps and Derivative Agreement (ISDA) between us and Enron North America. The write-off is also net of the expected recovery based on secondary market quotes from

the bond market. The amounts were written-off from the balances of the related assets and liabilities from risk management and trading activities on the Balance Sheets.

**Palo Verde Nuclear Generating Station**

Nuclear power plant operators are required to enter into spent fuel disposal contracts with the DOE, and the DOE is required to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE has announced that the repository cannot be completed before 2010 and that it does not intend to begin accepting spent nuclear fuel prior to that date. In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision preventing the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities filed damages actions against the DOE in the Court of Federal Claims.

In February 2002, the Secretary of Energy recommended to President Bush that the Yucca Mountain, Nevada site be developed as a permanent repository for spent nuclear fuel. The President transmitted this recommendation to Congress and the State of Nevada vetoed the President's recommendation. Congress approved the Yucca Mountain site, overriding the Nevada veto. It is now expected that the DOE will submit a license application to the NRC in late 2004.

We have existing fuel storage pools at Palo Verde and are in the process of completing construction of a new facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, we believe that spent nuclear fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Although some low-level waste has been stored on-site in a low-level waste facility, we are currently shipping low-level waste to off-site facilities. We currently believe that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

We currently estimate that we will incur $115 million (in 2002 dollars) over the life of Palo Verde for our share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2002, we had spent $2 million and had recorded accumulated spent nuclear fuel amortization of $44 million and a regulatory asset of $46 million for on-site interim spent nuclear fuel storage costs related to nuclear fuel burned to date.

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million ($300 million effective January 1, 2003) and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, we could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an

annual limit of $10 million per incident. Based on our interest in the three Palo Verde units, our maximum potential assessment per incident for all three units is approximately $77 million, with an annual payment limitation of approximately $9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. We have also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

**Purchased Power and Fuel Commitments**

We are party to various purchased power and fuel contracts with terms expiring from 2003 through 2025 that include required purchase provisions. We estimate the contract requirements to be approximately $135 million in 2003; $82 million in 2004; $28 million in 2005; $31 million in 2006; $17 million in 2007 and $162 million thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various purchased power and fuel contracts mentioned above some of those contracts have take-or-pay provisions. The contracts we have for the supply of our coal and nuclear fuel supply have take-or-pay provisions. The current take-or-pay nuclear fuel contracts expire in 2003, and had not been renewed as of December 31, 2002. The current take-or-pay coal contracts have terms that expire in 2007.

The following table summarizes the estimated take-or-pay commitments for the existing terms (dollars in millions):

| | Estimated Years Ending December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2004 | 2005 | 2006 | 2007 |
| Coal | $ 43 | $ 44 | $ 9 | $ 9 | $ 9 |
| Nuclear Fuel | 22 | -- | -- | -- | -- |
| Total take-or-pay commitments (a) | $ 65 | $ 44 | $ 9 | $ 9 | $ 9 |

(a) Total take-or-pay commitments are approximately $136 million. The total net present value of these commitments is approximately $119 million.

**Coal Mine Reclamation Obligations**

We must reimburse certain coal providers for amounts incurred for coal mine reclamation. Our coal mine reclamation obligation is about $59 million at December 31, 2002 and is included in deferred credits-other in the Balance Sheets.

A regulatory asset has been established for amounts not yet recovered from ratepayers related to the coal obligations. In accordance with the 1999 Settlement Agreement with the ACC, we are continuing to accelerate the amortization of the regulatory asset for coal mine reclamation over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Statements of Income.

**California Energy Market Issues and Refunds in the Pacific Northwest**

In July 2001, the FERC ordered an expedited fact-finding hearing to calculate refunds for spot market transactions in California during a specified time frame. This order calls for a hearing, with findings of fact due to the FERC after the ISO and PX provide necessary historical data. The FERC directed an ALJ to make findings of fact with respect to: (1) the mitigated price in each hour of the refund period; (2) the amount of refunds owed by each supplier according to the methodology established in the order; and (3) the amount currently owed to each supplier (with separate quantities due from each entity) by the CAISO, the California Power Exchange, the investor-owned utilities, and the State of California.

We were a seller and a purchaser in the California markets at issue, and to the extent that refunds are ordered, we should be a recipient as well as a payor of such amounts. On December 12, 2002, an ALJ issued Proposed Findings of Fact with respect to the refunds. On March 26, 2003, the FERC adopted the great majority of the proposed findings, revising only the calculation of natural gas prices for the final determination of mitigated prices in the California markets. Sellers who may actually have paid more for natural gas than the proxy prices adopted by the FERC have 40 days in which to submit necessary data to the FERC, after which a technical conference will be held. Finalization of refund amounts is expected in mid-2003. We do not anticipate material changes in our exposure and still believes, subject to the finalization of the revised proxy prices, that we will be entitled to a net refund.

On November 20, 2002, the FERC reopened discovery in these proceedings pursuant to instructions of the United States Court of Appeals for the Ninth Circuit, that the FERC permit parties to offer additional evidence of potential market manipulation for the period January 1, 2000 through June 20, 2001. Parties have submitted additional evidence and proposed findings, which the FERC continues to consider.

The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The FERC required that the record establish the volume of the transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds. On September 24, 2001, an ALJ concluded that prices in the Pacific Northwest during the period December 25, 2000 through June 20, 2001 were the result of a number of factors in addition to price signals from the California markets, including the shortage of supply, excess demand, drought, and increased natural gas prices. Under these circumstances, the ALJ ultimately concluded that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. The FERC is currently reviewing the ALJ's report and recommendations.

On December 19, 2002, the FERC opened a new discovery period to permit the parties to offer additional evidence for the period January 1, 2000 through June 20, 2001. Additional evidence has been submitted and a FERC decision on the newly submitted evidence is expected soon. Based on public comments from the FERC, it is anticipated that this case will be sent back to the ALJ for further proceedings on spot market and balance of month transactions.

Although the FERC has not yet made a final ruling in the Pacific Northwest matter nor calculated the specific refund amounts due in California, we do not expect that the resolution of these issues, as to the amounts alleged in the proceedings, will have a material adverse impact on our financial position, results of operations or liquidity.

On March 26, 2003, FERC made public a Final Report on Price Manipulation in Western Markets, prepared by its Staff and covering spot markets in the West in 2000 and 2001. The report stated that a significant number of entities who participated in the California markets during 2000-2001 time period, including APS, may potentially have been involved in arbitrage transactions that allegedly violated certain provisions of the ISO tariff. The report also recommended that the FERC issue an order to show cause why these transactions did not violate the ISO tariff with potential disgorgement of any unjust profits. Although APS has not yet had an opportunity to review the transactions at issue, it believes that it was not engaged in any such improper transactions. Based on the information available, it also appears that such transactions would not have a material adverse impact on our financial position, results of operation or liquidity.

SCE and PG&E have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the PX and the ISO. PG&E filed for bankruptcy protection in 2001.

**California Energy Market Litigation.** On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including the Company, failed to properly file rate information at the FERC in connection with sales to California from 2000 to the present. State of California v. British Columbia Power Exchange et. al., Docket No. EL02-71-000. The complaint requests the FERC to require the wholesale sellers to refund any rates that are "found to exceed just and reasonable levels." This complaint has been dismissed by the FERC and the State of California is now appealing the matter to the Ninth Circuit Court of Appeals. In addition, the State of California and others have filed various claims, which have now been consolidated, against several power suppliers to California alleging antitrust violations. Wholesale Electricity Antitrust Cases I and II, Superior Court in and for the County of San Diego, Proceedings Nos. 4204-00005 and 4204-00006. Two of the suppliers who were named as defendants in those matters, Reliant Energy Services, Inc. (and other Reliant entities) and Duke Energy and Trading, LLP (and other Duke entities), filed cross-claims against various other participants in the PX and ISO markets, including us, attempting to expand those matters to such other participants. We have not yet filed a responsive pleading in the matter, but we believe the claims by Reliant and Duke as they relate to us are without merit.

We were also named in a lawsuit regarding wholesale contracts in California. James Millar, et al. v. Allegheny Energy Supply, et al., United States District Court in and for the District of

Northern California, Case No. C02-2855 EMC. The complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market. The PX has filed a lawsuit against the State of California regarding the seizure of forward contracts and the State has filed a cross complaint against us and numerous other PX participants. Cal PX v. The State of California Superior Court in and for the County of Sacramento, JCCP No. 4203. Various preliminary motions are being filed and we cannot currently predict the outcome of this matter. The "United States Justice Foundation" is suing numerous wholesale energy contract suppliers to California, including Pinnacle West, as well as the California Department of Water Resources, based upon an alleged conflict of interest arising from the activities of a consultant for Edison International who also negotiated long-term contracts for the California Department of Water Resources. McClintock, et al. v. Yudhraja, Superior Court in and for the County of Los Angeles, Case No. GC 029447. The California Attorney General has indicated that an investigation by his office did not find evidence of improper conduct by the consultant. We believe the claims against Pinnacle West and us in the lawsuits mentioned in this paragraph are without merit and will have no material adverse impact on our financial position, results of operations or liquidity.

**Power Service Agreement**

By letter dated March 7, 2001, Citizens, which owns a utility in Arizona, advised us that it believes we overcharged Citizens by over $50 million under a power service agreement. We believe that our charges under the agreement were fully in accordance with the terms of the agreement. In addition, in testimony filed with the ACC on March 13, 2002, Citizens acknowledged that, based on its review, "if Citizens filed a complaint with FERC, it probably would lose the central issue in the contract interpretation dispute." We and Citizens terminated the power service agreement effective July 15, 2001. In replacement of the power service agreement, Pinnacle West and Citizens entered into a power sale agreement under which Pinnacle West will supply Citizens with future specified amounts of electricity and ancillary services through May 31, 2008. This new agreement does not address issues previously raised by Citizens with respect to charges under the original power service agreement through June 1, 2001.

**Letters of Credit**

We have entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2002 approximately $258 million of letters of credit were outstanding to support existing pollution control bonds of approximately $253 million. The letters of credit are available to fund the payment of principal and interest on such debt obligations. These letters of credit have expiration dates in 2003. We have also entered into approximately $115 million of letters of credit to support certain equity lessors in the Palo Verde sale-leaseback transactions (see Note 9 for further details on the Palo Verde sale-leaseback transactions). These letters of credit expire in 2005. Additionally, we have approximately $5 million of letters of credit related to counterparty collateral requirements and approximately $5 million of letters of credit related to workers' compensation expiring in 2003. We intend to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required.

**Indemnifications**

In conjunction with our financing agreements, including our sale-leaseback transactions, we generally provide indemnifications relating to liabilities arising from or related to the agreements, except with certain limited exceptions depending on the particular agreement. We have also provided indemnifications to the equity participants and other parties in the Palo Verde sale-leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnifications is likely and therefore no related liability has been recorded.

**Construction Program**

Total capital expenditures in 2003 are estimated at $401 million.

**Litigation**

We are party to various claims, legal actions and complaints arising in the ordinary course of business, including but not limited to environmental matters related to the Clean Air Act, Navajo Nation issues and ADEQ issues. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial statements, results of operations or liquidity.

## 11. Nuclear Decommissioning Costs

We recorded $11 million for nuclear decommissioning expense in each of the years 2002, 2001 and 2000. We estimate it will cost approximately $1.8 billion ($528 million in 2002 dollars) to decommission our share of the three Palo Verde units. The majority of decommissioning costs are expected to be incurred over a 14-year period beginning in 2024. We charge decommissioning costs to expense over each unit's operating license term and we include them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

Our current estimates are based on a 2001 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study. We are required by the ACC to update the study every three years.

To fund the costs we expect to incur to decommission the plant, we established external decommissioning trusts in accordance with NRC regulations and ACC orders. We invest the trust funds primarily in fixed income securities and domestic stock and classify them as available for sale. Realized and unrealized gains and losses are reflected in accumulated depreciation in accordance with industry practice. The following table shows the cost and fair value of our nuclear decommissioning trust fund assets, which were reported in investments and other assets on the Balance Sheets at December 31, 2002 and 2001 (dollars in millions):

| | 2002 | 2001 |
|---|---|---|
| Trust fund assets – at cost: | | |
| Fixed income securities | $ 113 | $ 103 |
| Domestic stock | 68 | 61 |
| Total | $ 181 | $ 164 |
| | | |
| Trust fund assets – fair value: | | |
| Fixed income securities | $ 117 | $ 106 |
| Domestic stock | 77 | 96 |
| Total | $ 194 | $ 202 |

See Note 2 for information on a new accounting standard on accounting for certain liabilities related to closure or removal of long-lived assets.

## 12. Selected Quarterly Financial Data (Unaudited)

Quarterly financial information for 2002 and 2001 is as follows:

| | (dollars in thousands) 2002 | | | |
|---|---|---|---|---|
| QUARTER ENDED | March 31 | June 30 | September 30 | December 31 |
| Electric operating revenues (a) | | | | |
| Regulated electricity segment | $ 383,741 | $ 507,711 | $ 744,463 | $ 423,424 |
| Marketing and trading segment | 10,693 | 2,369 | 9,126 | 11,866 |
| Operating income | $ 61,221 | $ 97,555 | $ 120,452 | $ 49,772 |
| Net income | $ 31,763 | $ 64,439 | $ 86,570 | $ 16,571 |

| | (dollars in thousands) 2001 | | | |
|---|---|---|---|---|
| QUARTER ENDED | March 31 | June 30 | September 30 | December 31 |
| Electric operating revenues (a) | | | | |
| Regulated electricity segment | $ 412,807 | $ 739,317 | $ 973,398 | $ 436,566 |
| Marketing and trading segment | 247,022 | 230,894 | 65,129 | 6,195 |
| Operating income | $ 97,034 | $ 95,238 | $ 135,139 | $ 71,567 |
| Income before accounting change | $ 64,606 | $ 69,639 | $ 107,556 | $ 38,887 |
| Cumulative effect of change in accounting – net of income tax | (2,755) | -- | (12,446) | -- |
| Net income | $ 61,851 | $ 69,639 | $ 95,110 | $ 38,887 |

(a) Our utility business is seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations. We have reclassified certain operating revenues to conform to the current presentation of netting energy trading contracts (see Note 16).

## 13. Fair Value of Financial Instruments

We believe that the carrying amounts of our cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 2002 and 2001 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 2002 and 2001 fair values of such investments, which we determine by using quoted market prices, approximate their carrying amount.

On December 31, 2002, the carrying value of our long-term debt (excluding capitalized lease obligations) was $2.21 billion, with an estimated fair value of $2.30 billion. The carrying value of our long-term debt (excluding capitalized lease obligations) was $2.08 billion on December 31, 2001, with an estimated fair value of $2.10 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

## 14. Stock-Based Compensation

Pinnacle West offers stock-based compensation plans for officers and key employees of our company.

In May 2002, Pinnacle West's shareholders approved the 2002 Long-term Incentive Plan (2002 plan), which allows Pinnacle West to grant performance shares, stock ownership incentive awards and non-qualified and performance-accelerated stock options to key employees. Pinnacle West has reserved 6 million shares of common stock for issuance under the 2002 plan. No more than

1.8 million shares may be issued in relation to performance share awards and stock ownership incentive awards. The plan also provides for the granting of new non-qualified stock options at a price per option not less than the fair market value of the common stock at the time of grant. The stock options vest over three years, unless certain performance criteria are met which can accelerate the vesting period. The term of the option cannot be longer than 10 years and the option cannot be repriced during its term.

The 1994 plan provides for the granting of new options (which may be non-qualified stock options or incentive stock options) of up to 3.5 million shares at a price per option not less than the fair market value on the date the option is granted. The 1985 plan includes outstanding options but no new options will be granted from the plan. Options vest one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The 1994 plan also provides for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

In the third quarter of 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123. The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in APB No. 25. We recorded approximately $333,000 in stock option expense before income taxes in our Statements of Income in 2002. This amount may not be reflective of the stock option expense we will record in future years because stock options typically vest over several years and additional grants are generally made each year.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The standard amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based compensation. The standard also amends the disclosure requirements of SFAS No. 123. SFAS No. 148 is effective for fiscal years ending after December 15, 2002. We adopted the disclosure requirements in 2002. See Note 1 for our pro forma disclosures on stock-based compensation and our weighted-average assumptions used to calculate the fair value of our stock options.

Total stock-based compensation expense, including stock option expense, was $3 million in 2002, $2 million in 2001 and $2 million in 2000.

## 15. Business Segments

We have two principal business segments (determined by services and the regulatory environment):

- our regulated electricity segment, which consists of regulated traditional retail and wholesale electricity businesses and related activities, and includes electricity transmission, distribution and generation; and

- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading. See Note 1 for information about the transfers of the marketing and trading division. See Note 1 for more information regarding our marketing and trading activities.

Financial data for the years ended December 31, 2002, 2001 and 2000 by business segments is provided as follows (dollars in millions):

| | Business Segments for Year Ended December 31, 2002 | | |
|---|---|---|---|
| | Regulated Electricity | Marketing and Trading | Total |
| Operating revenues | $ 2,059 | $ 34 | $ 2,093 |
| Purchased power and fuel costs | 595 | 33 | 628 |
| Other operating expenses | 604 | -- | 604 |
| Operating margin | 860 | 1 | 861 |
| Depreciation and amortization | 400 | -- | 400 |
| Interest and other expenses | 136 | -- | 136 |
| Pretax margin | 324 | 1 | 325 |
| Income taxes | 126 | -- | 126 |
| Net income | $ 198 | $ 1 | $ 199 |
| Total assets | $ 6,522 | $ -- | $ 6,522 |
| Capital expenditures | $ 501 | $ -- | $ 501 |

| | Business Segments for Year Ended December 31, 2001 | | |
|---|---|---|---|
| | Regulated Electricity | Marketing and Trading | Total |
| Operating revenues | $ 2,562 | $ 549 | $ 3,111 |
| Purchased power and fuel costs | 1,227 | 314 | 1,541 |
| Other operating expenses | 567 | -- | 567 |
| Operating margin | 768 | 235 | 1,003 |
| Depreciation and amortization | 421 | -- | 421 |
| Interest and other expenses | 119 | -- | 119 |
| Pretax margin | 228 | 235 | 463 |
| Income taxes | 90 | 93 | 183 |
| Income before accounting change | 138 | 142 | 280 |
| Cumulative effect of change in accounting for derivatives – net of income taxes of $10 | (15) | -- | (15) |
| Net income | $ 123 | $ 142 | $ 265 |
| Total assets | $ 6,052 | $ 174 | $ 6,226 |
| Capital expenditures | $ 471 | $ -- | $ 471 |

| | Business Segments for Year Ended December 31, 2000 | | |
|---|---|---|---|
| | Regulated Electricity | Marketing and Trading | Total |
| Operating revenues | $ 2,539 | $ 395 | $ 2,934 |
| Purchased power and fuel costs | 1,065 | 267 | 1,332 |
| Other operating expenses | 531 | -- | 531 |
| Operating margin | 943 | 128 | 1,071 |
| Depreciation and amortization | 425 | -- | 425 |
| Interest and other expenses | 144 | -- | 144 |
| Pretax margin | 374 | 128 | 502 |
| Income taxes | 146 | 49 | 195 |
| Net income | $ 228 | $ 79 | $ 307 |
| Total assets | $ 5,958 | $ 392 | $ 6,350 |
| Capital expenditures | $ 472 | $ -- | $ 472 |

## 16. Derivative and Trading Accounting

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these

market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

Effective January 1, 2001, we adopted SFAS No. 133. SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative instruments are either recognized periodically in income or, if hedge criteria is met, in common stock equity (as a component of other comprehensive income). We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. Hedge effectiveness is related to the degree to which the derivative contract and the hedged item are correlated. It is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. We exclude the time value of certain options from our assessment of hedge effectiveness. Any change in the fair value resulting from ineffectiveness, or the amount by which the derivative contract and the hedged commodity are not directly correlated, is recognized immediately in net income. See Note 1 for further discussion on our derivative instrument accounting policy.

In 2001, we recorded a $15 million after-tax charge in net income and a $72 million after-tax credit in common stock equity (as a component of other comprehensive income), both as cumulative effects of a change in accounting for derivatives. The charge primarily resulted from electricity option contracts. The credit resulted from unrealized gains on cash flow hedges.

In December 2001, the FASB issued revised guidance on the accounting for electricity contracts with option characteristics and the accounting for contracts that combine a forward contract and a purchased option contract. The effective date for the revised guidance was April 1, 2002. The impact of this guidance was immaterial to our financial statements.

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts and on January 1, 2003 for existing contracts, with early adoption permitted. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. The impact of this guidance was immaterial to our financial statements.

Both non-trading and trading derivatives are classified as assets and liabilities from risk management and trading activities in the Balance Sheets. For non-trading derivative instruments that qualify for cash flow hedge accounting treatment, changes in the fair value of the effective portion are recognized in common stock equity (as a component of accumulated other comprehensive income (loss)). Non-trading derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. Gains and losses related to non-trading derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If it becomes probable that a forecasted transaction will not occur, we discontinue the use of hedge accounting and recognize in income the unrealized gains and losses that were previously recorded in other comprehensive income (loss). In the event a non-trading derivative is terminated or settled, the unrealized gains and losses remain in other comprehensive income (loss), and are recognized in income when the underlying transaction impacts earnings.

Derivatives associated with trading activities are adjusted to fair value through income. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception and are not reflected on the balance sheet at fair value. Most of our electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered.

EITF 02-3 requires that derivatives held for trading purposes, whether settled financially or physically, be reported in the income statement on a net basis. Conversely, all non-trading contracts and derivatives are to be reported gross on the income statement. Previous guidance under EITF 98-10 permitted non-financially settled energy trading contracts to be reported either gross or net in the income statement. Beginning in the third quarter of 2002, we netted all of our energy trading activities on the Statements of Income and restated prior year amounts for all periods presented. Reclassification of such trading activity to a net basis of reporting resulted in reductions in both revenues and purchased power and fuel costs, but did not have any impact on our financial condition, results of operations or cash flows.

The changes in derivative fair value included in the Statements of Income for the years ended December 31, 2002 and 2001 are comprised of the following (dollars in thousands):

| | 2002 | 2001 |
|---|---|---|
| Gains/(losses) on the ineffective portion of derivatives qualifying for hedge accounting (a) | $ 8,482 | $ (6,056) |
| Losses from the discontinuance of cash flow hedges | (9,206) | (4,683) |
| Losses from non-hedge derivatives | (12,645) | (7,157) |
| Prior period mark-to-market losses realized upon delivery of commodities | 10,413 | 25,948 |
| Total pretax gain/(loss) | $ (2,956) | $ 8,052 |

(a) Time value component of options excluded from assessment of hedge effectiveness.

As of December 31, 2002, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions is approximately two years. During the twelve months ending December 31, 2003, we estimate that a net loss of $26 million before income taxes will be reclassified from accumulated other comprehensive loss as an offset to the effect on earnings of market price changes for the related hedged transactions.

**Credit Risk**

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We use a risk management process to assess and monitor the financial exposure of counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Credit valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See "Mark-to-Market Accounting" in Note 1 for a discussion of our credit valuation adjustment policy.

## 17. Other Income and Other Expense

The following table provides detail of other income and other expense for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

| | Year Ended December 31 | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Other income: | | | |
| Environmental insurance recovery | $ -- | $ 12,349 | $ -- |
| Equity earnings – net | -- | -- | 1,624 |
| Interest income | 3,455 | 5,004 | 4,924 |
| Miscellaneous | 1,694 | 2,854 | 3,142 |
| Total other income | $ 5,149 | $ 20,207 | $ 9,690 |
| Other expense: | | | |
| Equity losses – net | $ (1,131) | $ (3,355) | $ -- |
| Non-operating costs (a) | (16,424) | (14,637) | (14,853) |
| Miscellaneous | (1,783) | (2,798) | (5,694) |
| Total other expense | $ (19,338) | $ (20,790) | $ (20,547) |

(a) As defined by FERC, includes below-the-line non-operating utility costs (primarily community relations and environmental compliance).

## 18. Variable Interest Entities

In January 2003, the FASB issued FIN No. 46, "Consolidation of Variable Interest Entities." FIN No. 46 requires that we consolidate a VIE if we have a majority of the risk of loss from the VIE's activities or we are entitled to receive a majority of the VIE's residual returns or both. A VIE is a corporation, partnership, trust or any other legal structure that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities. FIN No. 46 is effective immediately for any VIE created after January 31, 2003 and is effective July 1, 2003 for VIEs created before February 1, 2003.

In 1986, we entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 8 for further information about the sale-leaseback transactions. Based on our preliminary assessment of FIN No. 46, we do not believe we will be required to consolidate the Palo Verde SPEs. However, we will continue to evaluate the requirements of the new guidance to determine what impact, if any, it will have on our financial statements.

We are exposed to losses under the Palo Verde sale-leaseback agreements upon the occurrence of certain events that we do not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), we would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2002, we would have been required to assume approximately $285 million of debt and pay the equity participants approximately $200 million.

## 19. Intangible Assets

On January 1, 2002, we adopted SFAS No. 142, "Goodwill and Other Intangible Assets." This statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes APB Opinion No. 17, "Intangible Assets." We have no goodwill recorded and have separately disclosed other intangible assets on our Balance Sheets. The intangible assets continue to be amortized over their finite useful lives. Thus, there was no impact on our financial position as a result of the adoption of SFAS No. 142. The Company's gross intangible assets (which are primarily software) were $193 million at December 31, 2002 and $170 million at December 31, 2001. The related accumulated amortization was $100 million at December 31, 2002 and $87 million at December 31, 2001. Amortization expense was $19 million in 2002, $21 million in 2001 and $20 million in 2000. Estimated amortization expense on existing intangible assets over the next five years is $21 million in 2003, $20 million in 2004, $19 million in 2005, $17 million in 2006 and $14 million in 2007.

## 20. Subsequent Events

See "ACC Applications" in Note 3 for information regarding the ACC's approval on March 27, 2003 of a $500 million financing arrangement between us and Pinnacle West Energy and "Track B Order" in Note 3 for information regarding the ACC order issued on March 14, 2003, mandating a process by which we must competitively procure energy.

See "California Energy Issues and Refunds in the Pacific Northwest" in Note 10 for information regarding the FERC's adoption on March 26, 2003 of an ALJ's proposed findings, and issuance on March 26, 2003 of a Final Report on Price Manipulation in Western Markets.

## ARIZONA PUBLIC SERVICE COMPANY
## SCHEDULE II – RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

| Column A | Column B | Column C Additions | | Column D | Column E |
|---|---|---|---|---|---|
| Description | Balance at beginning of period | Charged to cost and expenses | Charged to other accounts | Deductions | Balance at end of Period |
| **Reserve for uncollectibles** | | | | | |
| Year ended December 31, 2002 | $ 3,349 | $ 2,680 | $ -- | $ 4,688 | $ 1,341 |
| Year ended December 31, 2001 | $ 2,380 | $ 7,609 | $ -- | $ 6,640 | $ 3,349 |
| Year ended December 31, 2000 | $ 1,538 | $ 5,438 | $ -- | $ 4,596 | $ 2,380 |

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

# PART III

## ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Not applicable.

## ITEM 11. EXECUTIVE COMPENSATION

Not applicable.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Not applicable.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not applicable.

## ITEM 14. CONTROLS AND PROCEDURES

As of a date within 90 days of the date of this report (the "Evaluation Date"), we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Based upon this evaluation, our Chief Executive Officer and our Chief Financial Officer, concluded that, as of the Evaluation Date, our disclosure controls and procedures were adequate to ensure that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of the evaluation, including any corrective actions with regard to significant deficiencies and internal weaknesses.

## PART IV

## ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

**Financial Statements and Financial Statement Schedules**

See the Index to Financial Statements in Part II, Item 8.

**Exhibits Filed**

| *Exhibit No.* | | *Description* |
|---|---|---|
| 12.1 | — | Computation of Ratio of Earnings to Fixed Charges |
| 23.1 | — | Consent of Deloitte & Touche LLP |
| 99.1 | — | Certification of Jack E. Davis, the Company's principal executive officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 99.2 | — | Certification of Donald E. Brandt, the Company's principal financial officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 99.3 | — | Risk Factors |

In addition to those Exhibits shown above, the Company hereby incorporates the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation §229.10(d) by reference to the filings set forth below:

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 3.1 | Bylaws, amended as of September 18, 2002 | 3.2 to Pinnacle West September 2002 Form 10-Q Report | 1-8962 | 11-14-02 |
| 3.2 | Resolution of Board of Directors temporarily suspending Bylaws in part | 3.2 to 1994 Form 10-K Report | 1-4473 | 3-30-95 |
| 3.3 | Articles of Incorporation, restated as of May 25, 1988 | 4.2 to Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report | 1-4473 | 9-29-93 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 4.1 | Mortgage and Deed of Trust Relating to the Company's First Mortgage Bonds, together with forty-eight indentures supplemental thereto | 4.1 to September 1992 Form 10-Q Report | 1-4473 | 11-9-92 |
| 4.2 | Forty-ninth Supplemental Indenture | 4.1 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 4.3 | Fiftieth Supplemental Indenture | 4.2 to 1993 Form 10-K Report | 1-4473 | 3-30-94 |
| 4.4 | Fifty-first Supplemental Indenture | 4.1 to August 1, 1993 Form 8-K Report | 1-4473 | 9-27-93 |
| 4.5 | Fifty-second Supplemental Indenture | 4.1 to September 30, 1993 Form 10-Q Report | 1-4473 | 11-15-93 |
| 4.6 | Fifty-third Supplemental Indenture | 4.5 to Registration Statement No. 33-61228 by means of February 23, 1994 Form 8-K Report | 1-4473 | 3-1-94 |
| 4.7 | Fifty-fourth Supplemental Indenture | 4.1 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report | 1-4473 | 11-22-96 |
| 4.8 | Fifty-fifth Supplemental Indenture | 4.8 to Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report | 1-4473 | 4-9-97 |
| 4.9 | Fifty-sixth Supplemental Indenture | 4.1 to Pinnacle West 2002 Form 10-K Report | 1-8962 | 3-31-03 |
| 4.10 | Fifty-seventh Supplemental Indenture | 4.2 to Pinnacle West 2002 Form 10-K Report | 1-8962 | 3-31-03 |

| Exhibit No. | Description | Originally Filed as Exhibit: | File No.[b] | Date Effective |
|---|---|---|---|---|
| 4.11 | Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets | 4.1 to 1993 Form 10-K Report | 1-4473 | 3-30-94 |
| 4.12 | Indenture dated as of January 1, 1995 among the Company and The Bank of New York, as Trustee | 4.6 to Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report | 1-4473 | 1-11-95 |
| 4.13 | First Supplemental Indenture dated as of January 1, 1995 | 4.4 to Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report | 1-4473 | 1-11-95 |
| 4.14 | Indenture dated as of November 15, 1996 among the Company and The Bank of New York, as Trustee | 4.5 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report | 1-4473 | 11-22-96 |
| 4.15 | First Supplemental Indenture | 4.6 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report | 1-4473 | 11-22-96 |
| 4.16 | Second Supplemental Indenture dated as of April 1, 1997 | 4.10 to Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report | 1-4473 | 4-9-97 |
| 4.17 | Indenture dated as of January 15, 1998 among the Company and The Chase Manhattan Bank, as Trustee | 4.10 to Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report | 1-4473 | 1-16-98 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 4.18 | First Supplemental Indenture dated as of January 15, 1998 | 4.3 to Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report | 1-4473 | 1-16-98 |
| 4.19 | Second Supplemental Indenture dated as of February 15, 1999 | 4.3 to Registration Statement Nos. 333-27551 and 333-58445 by means of February 18, 1999 Form 8-K Report | 1-4473 | 2-22-99 |
| 4.20 | Third Supplemental Indenture dated as of November 1, 1999 | 4.5 to Registration Statement No. 333-58445 by means of November 2, 1999 Form 8-K Report | 1-4473 | 11-5-99 |
| 4.21 | Fourth Supplemental Indenture dated as of August 1, 2000 | 4.1 to Registration Statement Nos. 333-58445 and 333-94277 by means of August 2, 2000 Form 8-K Report | 1-4473 | 8-4-00 |
| 4.22 | Fifth Supplemental Indenture dated as of October 1, 2001 | 4.1 to September 2001 Form 10-Q | 1-4473 | 11-6-01 |
| 4.23 | Sixth Supplemental Indenture dated as of March 1, 2002 | 4.1 to Registration Statement Nos. 333-63994 and 333-83398 by means of February 26, 2002 Form 8-K Report | 1-4473 | 2-28-02 |
| 10.1 | Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between the Company and Mellon Bank, N.A., as Decommissioning Trustee | 10.2 to September 1991 Form 10-Q | 1-4473 | 11-14-91 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.2 | Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1) dated as of December 1, 1994 | 10.1 to 1994 Form 10-K Report | 1-4473 | 3-30-95 |
| 10.3 | Amendment No. 2 to Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991 | 10.4 to 1996 Form 10-K Report | 1-4473 | 3-28-97 |
| 10.4 | Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3) dated as of December 1, 1994 | 10.2 to 1994 Form 10-K Report | 1-4473 | 3-30-95 |
| 10.5 | Amendment No. 2 to Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991 | 10.6 to 1996 Form 10-K Report | 1-4473 | 3-28-97 |
| 10.6 | Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among the Company, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2 | 10.1 to Pinnacle West 1991 Form 10-K Report | 1-8962 | 3-26-92 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.7 | First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992 | 10.2 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 10.8 | Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of November 1, 1994 | 10.3 to 1994 Form 10-K Report | 1-4473 | 3-30-95 |
| 10.9 | Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992 | 10.1 to June 1996 Form 10-Q Report | 1-4473 | 8-9-96 |
| 10.10 | Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992 | 10.5 to 1996 Form 10-K Report | 1-4473 | 3-28-97 |
| 10.11 | Amendment No. 5 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of June 30, 2000 | 10.1 to Pinnacle West's March 2002 Form 10-Q Report | 1-8962 | 5-15-02 |
| 10.12 | Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of March 18, 2002 | 10.2 to Pinnacle West's March 2002 Form 10-Q Report | 1-8962 | 5-15-02 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.13 | Amendment No. 6 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of March 18, 2002 | 10.3 to Pinnacle West's March 2002 Form 10-Q Report | 1-8962 | 5-15-02 |
| 10.14 | Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of March 18, 2002 | 10.4 to Pinnacle West's March 2002 Form 10-Q Report | 1-8962 | 5-15-02 |
| 10.15 | Asset Purchase and Power Exchange Agreement dated September 21, 1990 between the Company and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991 | 10.1 to June 1991 Form 10-Q Report | 1-4473 | 8-8-91 |
| 10.16 | Long-Term Power Transactions Agreement dated September 21, 1990 between the Company and PacifiCorp, as amended as of October 11, 1990 and as of July 8, 1991 | 10.2 to June 1991 Form 10-Q Report | 1-4473 | 8-8-91 |
| 10.17 | Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP | 10.31 to Pinnacle West's Form S-14 Registration Statement | 2-96386 | 3-13-85 |
| 10.18 | Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transactions Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and the Company | 10.3 to 1995 Form 10-K Report | 1-4473 | 3-29-96 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.19 | Restated Transmission Agreement between PacifiCorp and the Company dated April 5, 1995 | 10.4 to 1995 Form 10-K Report | 1-4473 | 3-29-96 |
| 10.20 | Contract among PacifiCorp, the Company and United States Department of Energy Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995 | 10.5 to 1995 Form 10-K Report | 1-4473 | 3-29-96 |
| 10.21 | Reciprocal Transmission Service Agreement between the Company and PacifiCorp dated as of March 2, 1994 | 10.6 to 1995 Form 10-K Report | 1-4473 | 3-29-96 |
| 10.22 | Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant | 5.01 to Form S-7 Registration Statement | 2-59644 | 9-1-77 |
| 10.23 | Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant | 5.02 to Form S-7 Registration Statement | 2-59644 | 9-1-77 |
| 10.24 | Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease, Four Corners, dated April 25,1985 | 10.36 to Registration Statement on Form 8-B of Pinnacle West | 1-8962 | 7-25-85 |
| 10.25 | Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site | 5.04 to Form S-7 Registration Statement | 2-59644 | 9-1-77 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.26 | Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Power Plant Site, dated April 25, 1985 | 10.37 to Registration Statement on Form 8-B of Pinnacle West | 1-8962 | 7-25-85 |
| 10.27 | Four Corners Project Co-Tenancy Agreement Amendment No. 6 | 10.7 to Pinnacle West 2000 Form 10-K Report | 1-8962 | 3-14-01 |
| 10.28 | Application and Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Plant Site | 5.05 to Form S-7 Registration Statement | 2-59644 | 9-1-77 |
| 10.29 | Application and Amendment No. 1 to Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Power Plant Site, dated April 25, 1985 | 10.38 to Registration Statement on Form 8-B of Pinnacle West | 1-8962 | 7-25-85 |
| 10.30 | Indenture of Lease, Navajo Units 1, 2, and 3 | 5(g) to Form S-7 Registration Statement | 2-36505 | 3-23-70 |
| 10.31 | Application and Grant of rights-of-way and ease-ments, Navajo Plant | 5(h) to Form S-7 Registration Statement | 2-36505 | 3-23-70 |
| 10.32 | Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant | 5(l) to Form S-7 Registration Statement | 2-39442 | 3-16-71 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.33 | Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among the Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto | 10.1 to 1988 Form 10-K Report | 1-4473 | 3-8-89 |
| 10.34 | Amendment No. 13 dated as of April 22, 1991, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among the Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles | 10.1 to March 1991 Form 10-Q Report | 1-4473 | 5-15-91 |

| Exhibit No. | Description | Originally Filed as Exhibit: | File No.[b] | Date Effective |
|---|---|---|---|---|
| 10.35 | Amendment No. 14, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among the Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles | 10.4 to the Pinnacle West June 30, 2000 Form 10-Q Report | 1-8962 | 8-14-00 |
| 10.36[c] | Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee | 4.3 to Form S-3 Registration Statement | 33-9480 | 10-24-86 |
| 10.37[c] | Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee | 10.5 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8 | 1-4473 | 12-4-86 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.38[c] | Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee | 10.3 to 1988 Form 10-K Report | 1-4473 | 3-8-89 |
| 10.39[c] | Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee | 10.3 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 10.40 | Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee | 10.1 to November 18, 1986 Form 8-K Report | 1-4473 | 1-20-87 |
| 10.41 | Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee | 4.13 to Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report | 1-4473 | 8-24-87 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.42 | Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee | 10.4 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 10.43[a] | Directors' Deferred Compensation Plan, as restated, effective January 1, 1986 | 10.1 to June 1986 Form 10-Q Report | 1-4473 | 8-13-86 |
| 10.44[a] | Second Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of January 1, 1993 | 10.2 to 1993 Form 10-K Report | 1-4473 | 3-30-94 |
| 10.45[a] | Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan effective as of May 1, 1993 | 10.1 to September 1994 Form 10-Q | 1-4473 | 11-10-94 |
| 10.46[a] | Fourth Amendment dated December 28, 1999 to the Arizona Public Service Company Directors Deferred Compensation Plan | 10.8 to Pinnacle West's 1999 Form 10-K | 1-8962 | 3-30-00 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.47[a] | Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987, respectively | 10.4 to 1988 Form 10-K Report | 1-4473 | 3-8-89 |
| 10.48[a] | Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993 | 10.3 to 1993 Form 10-K Report | 1-4473 | 3-30-94 |
| 10.49[a] | Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993 | 10.2 to September 1994 Form 10-Q Report | 1-4473 | 11-10-94 |
| 10.50[a] | Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan | 10.3 to 1997 Form 10-K Report | 1-4473 | 3-28-97 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.51[a] | Sixth Amendment to Arizona Public Service Company Deferred Compensation Plan | 10.8 to Pinnacle West 2000 Form 10-K Report | 1-8962 | 3-14-01 |
| 10.52[a] | Schedules of William J. Post and Jack E. Davis to Arizona Public Service Company Deferred Compensation Plan, as amended | 10.2 to Pinnacle West Form 10-K Report | 1-8962 | 3-31-03 |
| 10.53[a] | Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996 | 10.10 to 1995 Form 10-K Report | 1-4473 | 3-29-96 |
| 10.54[a] | First Amendment effective as of January 1, 1999, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan | 10.6 to Pinnacle West's 1999 Form 10-K Report | 1-8962 | 3-30-00 |
| 10.55[a] | Second Amendment effective as of January 1, 2000, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan | 10.10 to Pinnacle West's 1999 Form 10-K Report | 1-8962 | 3-30-00 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.56[a] | Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, as amended and restated, dated December 7, 1999 | 10.13 to Pinnacle West's 1999 Form 10-K Report | 1-8962 | 3-30-00 |
| 10.57[a] | First Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan | 10.7 to Pinnacle West's 2001 Form 10-K Report | 1-8962 | 3-27-02 |
| 10.58[a] | Second Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan | 10.8 to Pinnacle West's 2001 Form 10-K Report | 1-8962 | 3-27-02 |
| 10.59[a] | Pinnacle West Capital Corporation and Arizona Public Service Company Directors' Retirement Plan effective as of January 1, 1995 | 10.7 to 1994 Form 10-K Report | 1-4473 | 3-30-95 |
| 10.60[a] | Pinnacle West Capital Corporation and Arizona Public Service Company Directors' Retirement Plan, as amended and restated on June 21, 2000 | 99.2 to Pinnacle West's Registration Statement on Form S-8 No. 333-40796 | 1-8962 | 7-3-00 |
| 10.61[a] | Arizona Public Service Company Director Equity Plan | 10.1 to September 1997 Form 10-K Report | 1-4473 | 11-12-97 |
| 10.62[a] | Letter Agreement dated December 21, 1993, between the Company and William L. Stewart | 10.6 to 1994 Form 10-K Report | 1-4473 | 3-30-95 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.63[a] | Letter Agreement dated August 16, 1996 between the Company and William L. Stewart | 10.8 to 1996 Form 10-K Report | 1-4473 | 3-28-97 |
| 10.64[a] | Letter Agreement between the Company and William L. Stewart | 10.2 to September 1997 Form 10-Q Report | 1-4473 | 11-12-97 |
| 10.65[a] | Letter Agreement dated December 13, 1999 between the Company and William L. Stewart | 10.9 to Pinnacle West's 1999 Form 10-K Report | 1-8962 | 3-30-00 |
| 10.66[a] | Amendment to Letter Agreement, effective as of January 1, 2002, between APS and William L. Stewart | 10.1 to Pinnacle West's June 2002 Form 10-Q Report | 1-8962 | 8-13-02 |
| 10.67[a] | Letter Agreement dated as of January 1, 1996 between the Company and Robert G. Matlock & Associates, Inc. for consulting services | 10.8 to 1995 Form 10-K Report | 1-4473 | 3-29-96 |
| 10.68[a] | Letter Agreement dated October 3, 1997 between the Company and James M. Levine | 10.17 to Pinnacle West's 1999 Form 10-K Report | 1-8962 | 3-30-00 |
| 10.69[a] | Summary of James M. Levine Retirement Benefits | 10.2 to Pinnacle West's March 2002 Form 10-Q Report | 1-8962 | 5-15-02 |
| 10.70[a] | Employment Agreement, effective as of October 1, 2002, between APS and James M. Levine | 10.1 to Pinnacle West's November 2002 Form 10-Q | 1-8962 | 11-14-02 |
| 10.71[a] | Letter Agreement dated June 28, 2001 between Pinnacle West Capital Corporation and Steve Wheeler | 10.4 to Pinnacle West's 2002 Form 10-K Report | 1-8962 | 3-31-03 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.72[ad] | Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries | 10.1 to Pinnacle West's June 1999 Form 10-Q Report | 1-8962 | 8-16-99 |
| 10.73[a] | Pinnacle West Capital Corporation Stock Option and Incentive Plan | 10.1 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 10.74[a] | First Amendment dated December 7, 1999 to the Pinnacle West Capital Corporation Stock Option and Incentive Plan | 10.11 to Pinnacle West's 1999 Form 10-K Report | 1-8962 | 3-30-00 |
| 10.75[a] | Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan effective as of March 23, 1994 | A to the Proxy Statement for the Plan Report Pinnacle West 1994 Annual Meeting of Shareholders | 1-8962 | 4-16-94 |
| 10.76[a] | First Amendment dated December 7, 1999, to the Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan | 10.12 to Pinnacle West's 1999 Form 10-K Report | 1-8962 | 3-30-00 |
| 10.77[a] | Pinnacle West Capital Corporation 2002 Long-Term Incentive Plan | 10.5 to Pinnacle West's 2002 Form 10-K Report | 1-8962 | 3-31-03 |
| 10.78[a] | Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans dated August 1, 1996 | 10.14 to Pinnacle West's 1999 Form 10-K Report | 1-8962 | 3-30-00 |

| Exhibit No. | Description | Originally Filed as Exhibit: | File No.[b] | Date Effective |
|---|---|---|---|---|
| 10.79[a] | First Amendment dated December 7, 1999, to the Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans | 10.15 to Pinnacle West's 1999 Form 10-K Report | 1-8962 | 3-30-00 |
| 10.80[a] | 2003 Management Officer Incentive Plan | 10.1 to Pinnacle West's 2002 Form 10-K Report | 1-8962 | 3-31-03 |
| 10.81[a] | 2003 CEO Variable Incentive Plan | 10.2 to Pinnacle West's 2002 Form 10-K Report | 1-8962 | 3-31-03 |
| 10.82 | Agreement No. 13904 (Option and Purchase of Effluent) with Cities of Phoenix, Glendale, Mesa, Scottsdale, Tempe, Town of Youngtown, and Salt River Project Agricultural Improvement and Power District, dated April 23, 1973 | 10.3 to 1991 Form 10-K Report | 1-4473 | 3-19-92 |
| 10.83 | Agreement for the Sale and Purchase of Wastewater Effluent with City of Tolleson and Salt River Agricultural Improvement and Power District, dated June 12, 1981,including Amendment No. 1 dated as of November 12, 1981 and Amendment No. 2 dated as of June 4, 1986 | 10.4 to 1991 Form 10-K Report | 1-4473 | 3-19-92 |
| 10.84 | Territorial Agreement between the Company and Salt River Project | 10.1 to March 1998 Form 10-Q Report | 1-4473 | 5-15-98 |
| 10.85 | Power Coordination Agreement between the Company and Salt River Project | 10.2 to March 1998 Form 10-Q Report | 1-4473 | 5-15-98 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 10.86 | Memorandum of Agreement between the Company and Salt River Project | 10.3 to March 1998 Form 10-Q Report | 1-4473 | 5-15-98 |
| 10.87 | Addendum to Memorandum of Agreement between the Company and Salt River Project dated as of May 19, 1998 | 10.2 to May 19, 1998 Form 8-K Report | 1-4473 | 6-26-98 |
| 99.1 | Collateral Trust Indenture among PVNGS II Funding Corp., Inc., the Company and Chemical Bank, as Trustee | 4.2 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 99.2 | Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., the Company and Chemical Bank, as Trustee | 4.3 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 99.3[c] | Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein | 28.1 to September 1992 Form 10-Q Report | 1-4473 | 11-9-92 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 99.4[c] | Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1,1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein | 10.8 to September 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8 | 1-4473 | 12-4-86 |
| 99.5[c] | Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein | 28.4 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |

| Exhibit No. | Description | Originally Filed as Exhibit: | File No.[b] | Date Effective |
|---|---|---|---|---|
| 99.6[c] | Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee | 4.5 to Form S-3 Registration Statement | 33-9480 | 10-24-86 |
| 99.7[c] | Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee | 10.6 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8 | 1-4473 | 12-4-86 |
| 99.8[c] | Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee | 4.4 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 99.9[c] | Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee | 28.3 to Form S-3 Registration Statement | 33-9480 | 10-24-86 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 99.10[c] | Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee | 10.10 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8 | 1-4473 | 12-4-86 |
| 99.11[c] | Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee | 28.6 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 99.12 | Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, the Company, and the Owner Participant named therein | 28.2 to September 1992 Form 10-Q Report | 1-4473 | 11-9-92 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 99.13 | Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, the Company, and the Owner Participant named therein | 28.20 to Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report | 1-4473 | 8-10-87 |
| 99.14 | Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Owner Participant named therein | 28.5 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 99.15 | Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee | 10.2 to November 18, 1986 Form 8-K Report | 1-4473 | 1-20-87 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 99.16 | Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee | 4.13 to Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report | 1-4473 | 8-24-87 |
| 99.17 | Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee | 4.5 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 99.18 | Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee | 10.5 to November 18, 1986 Form 8-K Report | 1-4473 | 1-20-87 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 99.19 | Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee | 28.7 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 99.20[c] | Indemnity Agreement dated as of March 17, 1993 by the Company | 28.3 to 1992 Form 10-K Report | 1-4473 | 3-30-93 |
| 99.21 | Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank | 28.20 to Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report | 1-4473 | 8-10-87 |
| 99.22 | Rate Reduction Agreement dated December 4, 1995 between the Company and the ACC Staff | 10.1 to December 4, 1995 Form 8-K Report | 1-4473 | 12-14-95 |
| 99.23 | Arizona Corporation Commission Order dated April 24, 1996 | 10.1 to March 1996 Form 10-Q Report | 1-4473 | 5-14-96 |
| 99.24 | Arizona Corporation Commission Order, Decision No. 59943, dated December 26, 1996, including the Rules regarding the introduction of retail competition in Arizona | 99.1 to 1996 Form 10-K Report | 1-4473 | 3-28-97 |
| 99.25 | Retail Electric Competition Rules | 10.1 to June 1998 Form 10-Q Report | 1-4473 | 8-14-98 |
| 99.26 | Arizona Corporation Commission Order, Decision No. 61973, dated October 6, 1999, approving our Settlement Agreement | 10.1 to September 1999 10-Q Report | 1-4473 | 11-15-99 |

| *Exhibit No.* | *Description* | *Originally Filed as Exhibit:* | *File No.*[b] | *Date Effective* |
|---|---|---|---|---|
| 99.27 | Arizona Corporation Commission Order, Decision No. 61969, dated September 29, 1999, including the Retail Electric Competition Rules | 10.2 to September 1999 10-Q Report | 1-4473 | 11-15-99 |
| 99.28 | Addendum to Settlement Agreement | 10.1 to Pinnacle West September 2000 10-Q | 1-8962 | 11-14-00 |
| 99.29 | ACC Opinion and Order dated September 10, 2002, Decision No. 65154 (Track A Order) | 99.1 to Pinnacle West's September 10, 2002 Form 8-K Report | 1-8962 | 9-17-02 |
| 99.30 | Arizona Public Service Company Application filed with the Arizona Corporation Commission on September 16, 2002 | 99.2 to Pinnacle West's September 10, 2002 Form 8-K Report | 1-8962 | 9-17-02 |
| 99.31 | Track "A" Appeals Issues - Principles for Resolution | 99.1 to Pinnacle West's November 15, 2002 Form 8-K Report | 1-8962 | 12-16-02 |

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[a]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 14(c) of Form 10-K.

[b]Reports filed under File No. 1-4473 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional officers and key employees of the Company. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

**Reports on Form 8-K**

During the quarter ended December 31, 2002 and the period ended March 31, 2003, the Company filed the following Reports on Form 8-K:

Report dated October 17, 2002 regarding Pinnacle West's earnings outlook.

Report dated November 14, 2002 regarding an ACC staff recommendation that the Interim Financing Application be approved.

Report dated November 15, 2002 regarding: (i) appeals of the Track A Order and an agreement between APS and the ACC staff; (ii) ACC staff testimony on the Financing Application; and (iii) EITF 02-3.

Report dated November 22, 2002 regarding ACC approval of the Interim Financing Application and Pinnacle West Energy's decision to cancel Redhawk Units 3 and 4.

Report dated January 15, 2003 regarding NAC losses and Pinnacle West's earnings outlook.

Report dated January 30, 2003 regarding an ACC staff report on Track B.

Report dated February 24, 2003 regarding reclassifications of revenue from electricity trading activities to a net basis of reporting.

Report dated February 27, 2003 regarding the ACC Track B decision.

Report dated March 11, 2003 regarding an ACC ALJ recommendation on the Financing Application.

Report dated March 27, 2003 regarding ACC approval of a financing arrangement.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Date: March 31, 2003

/s/ Jack E. Davis
(Jack E. Davis, President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ William J. Post<br>(William J. Post, Chairman of the Board of Directors ) | Director | March 31, 2003 |
| /s/ Jack E. Davis<br>(Jack E. Davis, President and Chief Executive Officer) | Principal Executive Officer and Director | March 31, 2003 |
| /s/ Donald E. Brandt<br>(Donald E. Brandt, Senior Vice President, and Chief Financial Officer) | Principal Financial Officer | March 31, 2003 |
| /s/ Chris N. Froggatt<br>(Chris N. Froggatt, Vice President and Controller) | Principal Accounting Officer | March 31, 2003 |
| /s/ Edward N. Basha, Jr.<br>(Edward N. Basha, Jr.) | Director | March 31, 2003 |

| | | |
|---|---|---|
| /s/ Michael L. Gallagher<br>(Michael L. Gallagher) | Director | March 31, 2003 |
| /s/ Pamela Grant<br>(Pamela Grant) | Director | March 31, 2003 |
| /s/ Roy A. Herberger, Jr.<br>(Roy A. Herberger, Jr.) | Director | March 31, 2003 |
| /s/ Martha O. Hesse<br>(Martha O. Hesse) | Director | March 31, 2003 |
| /s/ William S. Jamieson, Jr.<br>(William S. Jamieson, Jr.) | Director | March 31, 2003 |
| /s/ Humberto S. Lopez<br>(Humberto S. Lopez) | Director | March 31, 2003 |
| /s/ Robert G. Matlock<br>(Robert G. Matlock) | Director | March 31, 2003 |
| /s/ Kathryn L. Munro<br>(Kathryn L. Munro) | Director | March 31, 2003 |
| /s/ Bruce J. Nordstrom<br>(Bruce J. Nordstrom) | Director | March 31, 2003 |

CERTIFICATIONS

I, Jack E. Davis, certify that:

1. I have reviewed this annual report on Form 10-K of Arizona Public Service Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003.

/s/ Jack E. Davis
Jack E. Davis
President and Chief Executive Officer

I, Donald E. Brandt, certify that:

1. I have reviewed this annual report on Form 10-K of Arizona Public Service Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003.

/s/ Donald E. Brandt

Donald E. Brandt
Senior Vice President and Chief
Financial Officer

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ARIZONA PUBLIC SERVICE COMPANY
Projected Income Statements
Present and Proposed Rates
(Dollars in Thousands Except per Share Amounts)

| Line No. | Description | Actual Test Year Ended 12/31/2002 (a) | Projected Year Present Rates Year Ending 12/31/2003 (b) | Projected Year Present Rates Year Ending 12/31/2004 (b) | Projected Year Proposed Rates Year Ending 12/31/2004 (b) | Projected Year Present Rates Year Ending 12/31/2005 (b) | Projected Year Proposed Rates Year Ending 12/31/2005 (b) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1. | Electric Operating Revenues | $ 2,093,393 | $ 1,969,996 | $ 2,148,301 | $ 2,263,598 | $ 2,205,210 | $ 2,405,450 | 1. |
| 2. | Fuel and Purchased power | 628,030 | 567,774 | 657,096 | 644,350 | 667,792 | 666,142 | 2. |
| 3. | Operating Revenues Less Fuel and Purchased Power | 1,465,363 | 1,402,222 | 1,491,205 | 1,619,248 | 1,537,418 | 1,739,308 | 3. |
| | Other Operating Expenses: | | | | | | | |
| 4. | Oper & Maint excluding fuel expenses | 495,845 | 490,333 | 518,388 | 518,388 | 552,953 | 552,953 | 4. |
| 5. | Deprec & Amort | 399,640 | 385,736 | 370,585 | 370,585 | 408,045 | 408,045 | 5. |
| 6. | Income Taxes | 132,953 | 110,584 | 131,695 | 183,207 | 108,805 | 192,268 | 6. |
| 7. | Other Taxes | 107,925 | 113,500 | 120,650 | 120,650 | 134,989 | 134,989 | 7. |
| 8. | Operating Income | 329,000 | 302,069 | 349,887 | 426,418 | 332,626 | 451,053 | 8. |
| | Other Income (Deductions): | | | | | | | |
| 9. | Income Taxes | 6,148 | (627) | 1,089 | 1,089 | 5,491 | 5,491 | 9. |
| 10. | Other Income | 5,149 | 12,095 | 9,698 | 9,698 | 321 | 321 | 10. |
| 11. | Other Expenses | (19,338) | (10,508) | (12,454) | (12,454) | (14,223) | (14,223) | 11. |
| 12. | Total | (8,041) | 960 | (1,667) | (1,667) | (8,411) | (8,411) | 12. |
| 13. | Income Before Interest Deductions | 320,959 | 303,029 | 348,220 | 424,751 | 324,215 | 442,642 | 13. |
| | Interest Deductions | | | | | | | |
| 14. | Interest on long-term debt | 128,462 | 145,805 | 157,513 | 155,148 | 172,808 | 163,399 | 14. |
| 15. | Interest on short-term borrowings | 5,416 | 1,900 | 3,300 | 3,300 | 5,300 | 5,300 | 15. |
| 16. | Debt discount, premium and expense | 2,888 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 | 16. |
| 17. | Capitalized interest | (15,150) | (18,016) | (15,638) | (15,638) | (15,137) | (15,137) | 17. |
| 18. | Total | 121,616 | 132,689 | 148,175 | 145,810 | 165,971 | 156,562 | 18. |
| 19. | Net Income | $ 199,343 | $ 170,340 | $ 200,045 | $ 278,941 | $ 158,244 | $ 286,080 | 19. |
| | Earnings per share of average Common Stock Outstanding* | $ 2.80 | N/A | N/A | N/A | N/A | N/A | |
| | % Return on Average Common Equity | 9.2% | 7.9% | 8.4% | 11.5% | 6.0% | 10.4% | |
| | % Adjusted Return on Average Common Equity | 7.9% | 6.7% | 7.8% | 11.0% | 6.0% | 10.4% | |

Supporting Schedules:
(a) E-2

Recap Schedules:
(b) A-2

* Optional for projected years.

F-2

ARIZONA PUBLIC SERVICE COMPANY
Projected Changes in Financial Position
Present and Proposed Rates
(Thousands of Dollars)

| Line No. | Description | Actual Test Year 12/31/2002 | Projected Year Present Rates Year Ending 12/31/2003 | Projected Year Present Rates Year Ending 12/31/2004 | Projected Year Proposed Rates Year Ending 12/31/2004 | Projected Year Present Rates Year Ending 12/31/2005 | Projected Year Proposed Rates Year Ending 12/31/2005 | Line No. |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (b) | (b) | (b) | (b) | |
| | Cash Flows from Operations: | | | | | | | |
| 1. | Net Income | $ 199,343 | $ 170,340 | $ 200,045 | $ 278,941 | $ 158,244 | $ 286,080 | 1. |
| | Items not requiring cash: | | | | | | | |
| 2. | Depreciation and amortization | 399,640 | 385,736 | 370,585 | 370,585 | 408,045 | 408,045 | 2. |
| 3. | Nuclear fuel amortization | 31,185 | 37,618 | 38,481 | 38,481 | 38,974 | 38,974 | 3. |
| 4. | Deferred income taxes | 206,767 | (41,006) | (12,344) | (12,344) | (48,593) | (48,593) | 4. |
| 5. | Mark-to-market gains | 2,957 | - | - | - | - | - | 5. |
| 6. | Other | (135,380) | 88,575 | (92,691) | (92,081) | (51,462) | (50,126) | 6. |
| 7. | Net cash provided | 704,512 | 641,263 | 504,076 | 583,582 | 505,208 | 634,380 | 7. |
| | Cash Flows from Financing: | | | | | | | |
| 8. | Long-term debt | 459,926 | 500,000 | 458,506 | 379,000 | 587,086 | 457,914 | 8. |
| 9. | Short-term borrowings - net | (171,162) | 59,428 | 7,575 | 7,575 | 32,997 | 32,997 | 9. |
| 10. | Dividends paid on common stock | (170,000) | (170,000) | (170,000) | (170,000) | (170,000) | (170,000) | 10. |
| 11. | Repayment and requisition of long-term debt | (337,160) | (89,332) | (386,192) | (386,192) | (400,000) | (400,000) | 11. |
| 12. | Net cash used | (218,396) | 300,096 | (90,111) | (169,617) | 50,083 | (79,089) | 12. |
| | Cash Flows from Investing: | | | | | | | |
| 13. | Capital expenditures (before AFUDC debt) (c) | (490,156) | (411,899) | (386,883) | (386,883) | (528,710) | (528,710) | 13. |
| 14. | Allowance for borrowed funds used during construction (c | (15,150) | (18,016) | (15,638) | (15,638) | (15,137) | (15,137) | 14. |
| 15. | Loans to associated companies | - | (500,000) | - | - | - | - | 15. |
| 16. | Other | 44,918 | (11,444) | (11,444) | (11,444) | (11,444) | (11,444) | 16. |
| 17. | Net cash used | (460,388) | (941,359) | (413,965) | (413,965) | (555,291) | (555,291) | 17. |
| 18. | Net increase (decrease) in cash and cash equivalents | 25,728 | - | - | - | - | - | 18. |
| 19. | Cash and cash equivalents at beginning of period | 16,821 | 42,549 | 42,549 | 42,549 | 42,549 | 42,549 | 19. |
| 20. | Cash and cash equivalents at end of period | $ 42,549 | $ 42,549 | $ 42,549 | $ 42,549 | $ 42,549 | $ 42,549 | 20. |

Supporting Schedules:
(a) E-3
(c) F-3

Recap Schedules:
(b) A-5

F-3

ARIZONA PUBLIC SERVICE COMPANY
Projected Construction Requirements
Test Year and Three Projected Years
(Thousands of Dollars)

| Line No. | Description | Actual Test Year Ended 12/31/2002 | Projected Year Year Ended 12/31/2003 | Projected Year Year Ended 12/31/2004 | Projected Year Year Ended 12/31/2005 | Line No. |
|---|---|---|---|---|---|---|
| | Electric: | | | | | |
| 1. | Production Plant (Excluding Nuclear Fuel) | $ 108,428 | $ 89,416 | $ 69,202 | $ 152,029 | 1. |
| 2. | Nuclear Fuel | 30,862 | 29,458 | 28,693 | 28,474 | 2. |
| 3. | Total Production | 139,290 | 118,874 | 97,895 | 180,503 | 3. |
| 4. | Transmission | 106,452 | 56,720 | 54,946 | 79,921 | 4. |
| 5. | Distribution | 208,481 | 197,265 | 202,855 | 218,022 | 5. |
| 6. | General and Intangibles | 44,062 | 34,783 | 27,202 | 44,879 | 6. |
| 7. | Total Construction Expenditures (a) | 498,285 | 407,642 | 382,898 | 523,325 | 7. |
| 8. | Property Taxes Capitalized (a) | 2,958 | 4,257 | 3,985 | 5,385 | 8. |
| 9. | Allowance for Equity Funds Used During Construction | - | - | - | - | 9. |
| 10. | Allowance for Borrowed Funds Used During Construction | 13,507 | 18,016 | 15,638 | 15,137 | 10. |
| 11. | Total Capital Expenditures | $ 514,750 | $ 429,915 | $ 402,521 | $ 543,847 | 11. |

Supporting Schedules:
N/A

Recap Schedules:
(a) F-2 & A-4

F-4

ARIZONA PUBLIC SERVICE COMPANY
Assumptions Used in Developing Projections

| Line No. | Item | Line No. |
|---|---|---|
| | **A. Customer Growth** | |
| 1. | Retail customer growth for the period 1/1/03 through 12/31/05 is forecasted to grow at an annual average rate of 3.4%. | 1. |
| | **B. Growth in Retail Energy and Retail Peak Demand** | |
| 2. | Retail energy sales for the period 1/1/03 through 12/31/05 are forecasted to grow at an annual average rate of 4.8%. Retail | 2. |
| 3. | summer and winter peak demands for the same period are forecasted to grow at annual average rates of 4.3% and 2.9%, | 3. |
| 4. | respectively. | 4. |
| | **C. Wholesale and Economy Interchange Sales** | |
| 5. | Firm wholesale sales and peak demand for obligation-to-serve customers are forecasted per existing contracts. The | 5. |
| 6. | Company sells energy on an economy interchange basis on a short-term basis from time to time. Such sales are made | 6. |
| 7. | at prices above the Company's variable costs to generate energy. | 7. |
| | **D. Fuel** | |
| 8. | Fuel costs are based on projected sales, estimated fuel prices and projected operating availability factors of power | 8. |
| 9. | plants. | 9. |
| | **E. Operations & Maintenance Expenses** | |
| 10. | The level of expenses reflect increases that are related to inflation and increased benefits costs, the current trend | 10. |
| 11. | of increased customers and additional plant requirements. | 11. |
| | **F. Construction Expenditures** | |
| 12. | The level of expenditures is primarily driven by customer, sales, and load growth, maintaining reliability, and legal | 12. |
| 13. | and regulatory requirements. | 13. |
| | **G. Capital Structure Changes** | |
| 14. | Capital Structure and Financing are shown on Schedules A-3, D-1, D-2, D-3 and F-2. | 14. |
| | **H. Financing Assumptions** | |
| 15. | Forecasted Interest Rates: | 15. |
| 16. | Variable Rate Pollution Control Bonds - 1.31% in 2003, 2.05% in 2004, 3.35% in 2005 | 16. |
| 17. | Commercial Paper - 1.9% in 2003, 3.3% in 2004, 5.3% in 2005 | 17. |
| 18. | New Sr. Unsecured Debt - 7.0% in 2004, 7.5% in 2005 | 18. |

G-1

**ARIZONA PUBLIC SERVICE COMPANY**
**Cost of Service Summary - *Present Rates***
**Rates of Return by Customer Classification**
**Adjusted Test Year Ending December 31, 2002**
**($000)**

| | | | | | Total ACC Jurisdiction | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Total Company | Total ACC Jurisdiction | All Other | Residential | General Service | Irrigation | Street Lighting | Dusk to Dawn |
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
| 1.a. | Revenues from Rates | 1,827,189 | 1,791,584 (a) | 35,605 | 889,898 (a) | 883,595 (a) | 2,099 (a) | 10,794 (a) | 5,198 (a) |
| 1.b. | Other Revenues | 150,987 | 148,562 | 2,425 | 71,187 | 74,249 | 215 | 2,582 | 329 |
| 2. | Expenses | 1,626,563 | 1,590,132 (b) | 36,432 | 839,733 (b) | 730,686 (b) | 2,360 (b) | 12,439 (b) | 4,914 (b) |
| 3. | Operating Income Before Income Taxes | 351,613 | 350,014 | 1,598 | 121,352 | 227,158 | (46) | 937 | 613 |
| 4. | Income Taxes | 86,608 | 86,144 | 463 | 18,616 | 67,806 | -75 | -195 | -7 |
| 5. | Net Operating Income | 265,005 | 263,870 | 1,135 | 102,736 | 159,352 | 29 | 1,132 | 620 |
| 6. | Rate Base | 4,221,019 | 4,207,476 (c) | 13,543 | 2,367,112 (c) | 1,769,998 (c) | 4,571 (c) | 45,676 (c) | 20,118 (c) |
| 7. | Rate of Return | 6.28% | 6.27% | 8.38% | 4.34% | 9.00% | 0.63% | 2.48% | 3.08% |

Supporting Schedules:
(a) H-1
(b) G-4
(c) G-3

G-2

**ARIZONA PUBLIC SERVICE COMPANY**
**Cost of Service Summary - *Proposed Rates***
**Rates of Return by Customer Classification**
**Adjusted Test Year Ending December 31, 2002**
**($000)**

| | | | | | Total ACC Jurisdiction | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Total Company | Total ACC Jurisdiction | All Other | Residential | General Service | Irrigation | Street Lighting | Dusk to Dawn |
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
| 1.a. | Revenues from Rates | 1,993,996 | 1,958,391 (a) | 35,605 | 972,747 (a) | 965,868 (a) | 2,295 (a) | 11,799 (a) | 5,682 (a) |
| 1.b. | Other Revenues | 150,987 | 148,562 | 2,425 | 71,187 | 74,249 | 215 | 2,582 | 329 |
| 2. | Expenses | 1,626,563 | 1,590,132 (b) | 36,432 | 839,733 (b) | 730,686 (b) | 2,360 (b) | 12,439 (b) | 4,914 (b) |
| 3. | Operating Income Before Income Taxes | 518,420 | 516,821 | 1,598 | 204,201 | 309,431 | 150 | 1,942 | 1,097 |
| 4. | Income Taxes | 152,496 | 152,033 | 463 | 51,968 | 99,684 | 1 | 197 | 183 |
| 5. | Net Operating Income | 365,924 | 364,788 | 1,135 | 152,233 | 209,747 | 149 | 1,745 | 914 |
| 6. | Rate Base | 4,221,019 | 4,207,476 (c) | 13,543 | 2,367,112 (c) | 1,769,998 (c) | 4,571 (c) | 45,676 (c) | 20,118 (c) |
| 7. | Rate of Return | 8.67% | 8.67% | 8.38% | 6.43% | 11.85% | 3.26% | 3.82% | 4.54% |

Supporting Schedules:
(a) H-1
(b) G-4
(c) G-3

G-3

**ARIZONA PUBLIC SERVICE COMPANY**
**Rate Base Allocation to Classes of Service**
**Total Rate Base**
**Adjusted Test Year Ending December 31, 2002**
**($000)**

| Line No. | Class of Service | Production - Demand | Transmission Substation | Transmission Lines | Distribution Substation | Distribution OH Primary | Distribution OH Secondary | Distribution UG Lines | Distribution Line TXFs | Total Demand | Total Demand % | Total Energy | Total Energy % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) |
| 1. | Residential | 1,062,376 | 0 | 0 | 87,562 | 147,786 | 67,667 | 438,874 | 198,240 | 2,002,505 | 55.13% | 43,910 | 45.23% |
| 2. | General Service | 985,723 | 0 | 0 | 73,149 | 117,803 | 14,607 | 318,641 | 102,044 | 1,611,969 | 44.38% | 52,429 | 54.01% |
| 3. | Irrigation | 3,327 | 0 | 0 | 946 | 1,596 | 0 | 0 | 361 | 6,230 | 0.17% | 132 | 0.14% |
| 4. | Street Lighting | 0 | 0 | 0 | 875 | 1,477 | 593 | 4,321 | 1,083 | 8,349 | 0.23% | 441 | 0.45% |
| 5. | Dusk to Dawn | 0 | 0 | 0 | 325 | 548 | 220 | 1,604 | 402 | 3,099 | 0.09% | 164 | 0.17% |
| 6. | Total | 2,051,426 (b) | 0 | 0 | 162,857 (b) | 269,211 (b) | 83,087 (b) | 763,440 (b) | 302,131 (b) | 3,632,152 | 100.00% | 97,076 | 100.00% |

| | Class of Service | Cust. Advances & Deposits | Distribution OH Services | Distribution UG Services | Distribution Meters | Customer Accounts | Dusk to Dawn | Street Lighting | Customer Service & Info | Sales | Total Customer | Total Customer % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) |
| 7. | Residential | (48,220) | 23,377 | 112,951 | 83,928 | 49,075 | 0 | 0 | 1,396 | 9,720 | 232,226 | 77.08% |
| 8. | General Service | (33,879) | 2,511 | 11,113 | 30,600 | 5,994 | 0 | 0 | 170 | 1,187 | 17,696 | 5.87% |
| 9. | Irrigation | (2,425) | 37 | 0 | 295 | 22 | 0 | 0 | 1 | 4 | (2,066) | -0.69% |
| 10. | Street Lighting | (728) | 0 | 0 | 0 | 45 | 0 | 37,339 | 1 | 9 | 36,666 | 12.17% |
| 11. | Dusk to Dawn | (125) | 0 | 0 | 0 | 475 | 16,317 | 0 | 14 | 94 | 16,774 | 5.57% |
| 12. | Total | (85,378) (b) | 25,925 (b) | 124,064 (b) | 114,824 (b) | 55,610 (b) | 16,317 (b) | 37,339 (b) | 1,582 (b) | 11,014 (b) | 301,296 | 100.00% |

| | Class of Service | Total Reg. Assets | Total Reg. Assets % | Total System Benefits | Total System Benefits % | TOTAL ACC JURIS. (a) | TOTAL ACC JURIS. % |
|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) |
| 13. | Residential | 87,306 | 50.07% | 1,165 | 45.23% | 2,367,112 | 56.26% |
| 14. | General Service | 86,514 | 49.61% | 1,391 | 54.01% | 1,769,998 | 42.07% |
| 15. | Irrigation | 271 | 0.16% | 4 | 0.14% | 4,571 | 0.11% |
| 16. | Street Lighting | 208 | 0.12% | 12 | 0.45% | 45,676 | 1.09% |
| 17. | Dusk to Dawn | 77 | 0.04% | 4 | 0.17% | 20,118 | 0.48% |
| 18. | | 174,376 (b) | 100.00% | 2,576 (b) | 100.00% | 4,207,476 | 100.00% |

Supporting Schedules:
(b) G-5
(c) G-7

Recap Schedules:
(a) G-1 & G-2

G-4

**ARIZONA PUBLIC SERVICE COMPANY**
**Expense Allocation to Classes of Service**
**Operating Expenses Excluding Income Taxes**
**Adjusted Test Year Ending December 31, 2002**
**($000)**

| Line No. | Class of Service | Production - Demand | Transmission Substation | Transmission Lines | Distribution Substation | Distribution OH Primary | Distribution OH Secondary | Distribution UG Lines | Distribution Line TXFs | Total Demand | Total Demand % | Total Energy | Total Energy % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) |
| 1. | Residential | 245,691 | 0 | 46,610 | 15,020 | 20,171 | 9,314 | 41,724 | 20,572 | 399,102 | 53.28% | 278,597 | 45.23% |
| 2. | General Service | 228,814 | 0 | 46,031 | 12,548 | 16,079 | 2,011 | 30,294 | 10,589 | 346,365 | 46.24% | 332,650 | 54.01% |
| 3. | Irrigation | 763 | 0 | 117 | 162 | 218 | 0 | 0 | 37 | 1,297 | 0.17% | 838 | 0.14% |
| 4. | Street Lighting | 140 | 0 | 565 | 150 | 202 | 82 | 411 | 112 | 1,661 | 0.22% | 2,800 | 0.45% |
| 5. | Dusk to Dawn | 65 | 0 | 264 | 56 | 75 | 30 | 152 | 42 | 684 | 0.09% | 1,038 | 0.17% |
| 6. | Total | 475,472 (a) | 0 (a) | 93,587 (a) | 27,936 (a) | 36,745 (a) | 11,436 (a) | 72,580 (a) | 31,352 (a) | 749,109 | 100.00% | 615,923 | 100.00% |

| | Class of Service | Distribution OH Services | Distribution UG Services | Distribution Meters | Customer Accounts | Dusk to Dawn | Street Lighting | Customer Service & Info | Sales | Total Customer | Total Customer % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
| 7. | Residential | 3,228 | 10,781 | 27,826 | 69,973 | 0 | 0 | 3,828 | 19,705 | 135,341 | 79.90% |
| 8. | General Service | 347 | 1,061 | 10,145 | 8,547 | 0 | 0 | 468 | 2,407 | 22,973 | 13.56% |
| 9. | Irrigation | 5 | 0 | 98 | 31 | 0 | 0 | 2 | 9 | 145 | 0.09% |
| 10. | Street Lighting | 0 | 0 | 0 | 64 | 0 | 7,714 | 3 | 18 | 7,799 | 4.60% |
| 11. | Dusk to Dawn | 0 | 0 | 0 | 677 | 2,218 | 0 | 37 | 191 | 3,123 | 1.84% |
| 12. | Total | 3,580 (a) | 11,841 (a) | 38,069 (a) | 79,292 (a) | 2,218 (a) | 7,714 (a) | 4,338 (a) | 22,329 (a) | 169,381 | 100.00% |

| | Class of Service | Total Reg. Assets | Total Reg. Assets % | Total System Benefits | Total System Benefits % | TOTAL ACC JURIS. (c) | TOTAL ACC JURIS. % |
|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) |
| 13. | Residential | 9,743 | 51.77% | 16,951 | 45.94% | 839,733 | 52.81% |
| 14. | General Service | 9,046 | 48.07% | 19,651 | 53.26% | 730,686 | 45.95% |
| 15. | Irrigation | 31 | 0.16% | 49 | 0.13% | 2,360 | 0.15% |
| 16. | Street Lighting | 0 | 0.00% | 178 | 0.48% | 12,439 | 0.78% |
| 17. | Dusk to Dawn | 0 | 0.00% | 70 | 0.19% | 4,914 | 0.31% |
| 18. | Total | 18,820 (a) | 100.00% (a) | 36,899 (a) | 100.00% | 1,590,132 | 100.00% |

Supporting Schedules:
(a) G-6
(b) G-7

Recap Schedules:
(c) G-1 & G-2

G-5

**ARIZONA PUBLIC SERVICE COMPANY**
**Distribution of Rate Base by Function**
**Total Rate Base**
**Adjusted Test Year Ending December 31, 2002**
**($000)**

| Line No. | Plant Classification | Production - Demand | Transmission Substation | Transmission Lines | Distribution Substation | Distribution OH Primary | Distribution OH Secondary | Distribution UG Lines | Distribution Line TXFs | Total Demand | Total Demand % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
| 1. | Production - Demand | 2,051,426 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,051,426 | 56.48% |
| 2. | Transmission Substation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.00% |
| 3. | Transmission Lines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.00% |
| 4. | Distribution Substation | 0 | 0 | 0 | 162,857 | 0 | 0 | 0 | 0 | 162,857 | 4.48% |
| 5. | Distribution OH Primary | 0 | 0 | 0 | 0 | 269,211 | 0 | 0 | 0 | 269,211 | 7.41% |
| 6. | Distribution OH Secondary | 0 | 0 | 0 | 0 | 0 | 83,087 | 0 | 0 | 83,087 | 2.29% |
| 7. | Distribution UG Lines | 0 | 0 | 0 | 0 | 0 | 0 | 763,440 | 0 | 763,440 | 21.02% |
| 8. | Distribution Line TXFs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 302,131 | 302,131 | 8.32% |
| 9. | Total | 2,051,426 | 0 | 0 | 162,857 | 269,211 | 83,087 | 763,440 | 302,131 | 3,632,152 | 100.00% |

| | Plant Classification | Cust. Advances & Deposits | Distribution OH Services | Distribution UG Services | Distribution Meters | Customer Accounts | Dusk to Dawn | Street Lighting | Customer Service & Info | Sales | Total Customer | Total Customer % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) |
| 10. | Cust. Advances & Deposit | (85,378) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (85,378) | -28.34% |
| 11. | Distribution OH Services | 0 | 25,925 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 25,925 | 8.60% |
| 12. | Distribution UG Services | 0 | 0 | 124,064 | 0 | 0 | 0 | 0 | 0 | 0 | 124,064 | 41.18% |
| 13. | Distribution Meters | 0 | 0 | 0 | 114,824 | 0 | 0 | 0 | 0 | 0 | 114,824 | 38.11% |
| 14. | Customer Accounts | 0 | 0 | 0 | 0 | 55,610 | 0 | 0 | 0 | 0 | 55,610 | 18.46% |
| 15. | Dusk to Dawn | 0 | 0 | 0 | 0 | 0 | 16,317 | 0 | 0 | 0 | 16,317 | 5.42% |
| 16. | Street Lighting | 0 | 0 | 0 | 0 | 0 | 0 | 37,339 | 0 | 0 | 37,339 | 12.39% |
| 17. | Customer Service & Info | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,582 | 0 | 1,582 | 0.52% |
| 18. | Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11,014 | 11,014 | 3.66% |
| 19. | Total | (85,378) | 25,925 | 124,064 | 114,824 | 55,610 | 16,317 | 37,339 | 1,582 | 11,014 | 301,296 | 100.00% |

| | Plant Classification | Total Energy | Total Energy % | Total Reg. Assets | Total Reg. Assets % | Total System Benefits | Total System Benefits % | TOTAL ACC JURIS. (a) |
|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
| 20. | Production - Energy | 97,076 | 100.00% | | | | | |
| 21. | Regulatory Assets | | | 174,376 | 100.00% | | | |
| 22. | System Benefits | | | | | 2,576 | 100.00% | |
| 23. | TOTAL ACC | | | | | | | 4,207,476 |

Supporting Schedules:

Recap Schedules:
(a) G-3

G-6

**ARIZONA PUBLIC SERVICE COMPANY**
**Distribution of Expenses by Function**
**Operating Expenses Excluding Income Taxes**
**Adjusted Test Year Ending December 31, 2002**
**($000)**

| Line No. | Plant Classification | Production - Demand | Transmission Substation | Transmission Lines | Distribution Substation | Distribution OH Primary | Distribution OH Secondary | Distribution UG Lines | Distribution Line TXFs | Total Demand | Total Demand % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
| 1. | Production - Demand | 475,472 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 475,472 | 63.47% |
| 2. | Transmission Substation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.00% |
| 3. | Transmission Lines | 0 | 0 | 93,587 | 0 | 0 | 0 | 0 | 0 | 93,587 | 12.49% |
| 4. | Distribution Substation | 0 | 0 | 0 | 27,936 | 0 | 0 | 0 | 0 | 27,936 | 3.73% |
| 5. | Distribution OH Primary | 0 | 0 | 0 | 0 | 36,745 | 0 | 0 | 0 | 36,745 | 4.91% |
| 6. | Distribution OH Secondary | 0 | 0 | 0 | 0 | 0 | 11,436 | 0 | 0 | 11,436 | 1.53% |
| 7. | Distribution UG Lines | 0 | 0 | 0 | 0 | 0 | 0 | 72,580 | 0 | 72,580 | 9.69% |
| 8. | Distribution Line TXFs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 31,352 | 31,352 | 4.19% |
| 9. | Total | 475,472 | 0 | 93,587 | 27,936 | 36,745 | 11,436 | 72,580 | 31,352 | 749,109 | 100.00% |

| | Plant Classification | Distribution OH Services | Distribution UG Services | Distribution Meters | Customer Accounts | Dusk to Dawn | Street Lighting | Customer Service & Info | Sales | Total Customer | Total Customer % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
| 10. | Distribution OH Services | 3,580 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,580 | 2.11% |
| 11. | Distribution UG Services | 0 | 11,841 | 0 | 0 | 0 | 0 | 0 | 0 | 11,841 | 6.99% |
| 12. | Distribution Meters | 0 | 0 | 38,069 | 0 | 0 | 0 | 0 | 0 | 38,069 | 22.48% |
| 13. | Customer Accounts | 0 | 0 | 0 | 79,292 | 0 | 0 | 0 | 0 | 79,292 | 46.81% |
| 14. | Dusk to Dawn | 0 | 0 | 0 | 0 | 2,218 | 0 | 0 | 0 | 2,218 | 1.31% |
| 15. | Street Lighting | 0 | 0 | 0 | 0 | 0 | 7,714 | 0 | 0 | 7,714 | 4.55% |
| 16. | Customer Service & Info | 0 | 0 | 0 | 0 | 0 | 0 | 4,338 | 0 | 4,338 | 2.56% |
| 17. | Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 22,329 | 22,329 | 13.18% |
| 18. | Total | 3,580 | 11,841 | 38,069 | 79,292 | 2,218 | 7,714 | 4,338 | 22,329 | 169,381 | 100.00% |

| | Plant Classification | Total Production - Energy | Total Energy % | Total Reg. Assets | Total Reg. Assets % | Total System Benefits | Total System Benefits % | TOTAL ACC JURIS. (a) |
|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
| 19. | Production - Energy | 615,923 | 100.00% | | | | | |
| 20. | Regulatory Assets | | | 18,820 | 100.00% | | | |
| 21. | System Benefits | | | | | 36,899 | 100.00% | |
| 22. | TOTAL ACC | | | | | | | 1,590,132 |

Supporting Schedules:

Recap Schedules:
(a) G-4

G-7

**ARIZONA PUBLIC SERVICE COMPANY**
**Cost of Service Study**
**Development of Allocation Factors**
**Adjusted Test Year Ending December 31, 2002**

| Factor | Definition and Application of Allocation Factor | Total Company | Total ACC Jurisdiction | All Other | Total Retail | Residential | General Service | Irrigation | Street Lighting | Dusk to Dawn |
|---|---|---|---|---|---|---|---|---|---|---|
| 1. DEMPROD1 | 4-CP Demand @ Generation (KW) | 5,111,775 | 5,102,910 | 8,865 | 5,102,910 | 2,642,653 | 2,451,981 | 8,276 | 0 | 0 |
| | Production Demand | 100.00% | 99.83% | 0.17% | 99.83% | 51.70% | 47.97% | 0.16% | 0.00% | 0.00% |
| 2. DEMPROD2 | 4-CP Demand @ Generation (KW) | 5,111,775 | 5,102,910 | 8,865 | 5,102,910 | 2,642,653 | 2,451,981 | 8,276 | 0 | 0 |
| | Production - Ancillary Service - Regulation | 100.00% | 99.83% | 0.17% | 99.83% | 51.70% | 47.97% | 0.16% | 0.00% | 0.00% |
| 3. DEMPROD3 | 4-CP Demand @ Generation (KW) | 5,111,775 | 5,102,910 | 8,865 | 5,102,910 | 2,642,653 | 2,451,981 | 8,276 | 0 | 0 |
| | Production - Ancillary Service - Spinning Reserve | 100.00% | 99.83% | 0.17% | 99.83% | 51.70% | 47.97% | 0.16% | 0.00% | 0.00% |
| 4. DEMPROD4 | 4-CP Demand @ Generation (KW) | 5,111,775 | 5,102,910 | 8,865 | 5,102,910 | 2,642,653 | 2,451,981 | 8,276 | 0 | 0 |
| | Production - Ancillary Service - Ready Reserve | 100.00% | 99.83% | 0.17% | 99.83% | 51.70% | 47.97% | 0.16% | 0.00% | 0.00% |
| 5. DEMPROD6 | 4-CP Demand @ Generation (KW) | 5,111,775 | 5,102,910 | 8,865 | 5,102,910 | 2,642,653 | 2,451,981 | 8,276 | 0 | 0 |
| | Production - Ancillary Service - Scheduling & Dispatch | 100.00% | 99.83% | 0.17% | 99.83% | 51.70% | 47.97% | 0.16% | 0.00% | 0.00% |
| 6. DEMPROD7 | 4-CP Demand @ Generation (KW) | 5,111,775 | 5,102,910 | 8,865 | 5,102,910 | 2,642,653 | 2,451,981 | 8,276 | 0 | 0 |
| | Production - Ancillary Service - Must Run | 100.00% | 99.83% | 0.17% | 99.83% | 51.70% | 47.97% | 0.16% | 0.00% | 0.00% |
| 7. DEMTRAN1 | 4-CP Demand @ Generation including Wheeling (KW) | 6,445,773 | 5,102,910 | 1,342,863 | 5,102,910 | 2,642,653 | 2,451,981 | 8,276 | 0 | 0 |
| | Transmission Substation | 100.00% | 79.17% | 20.83% | 79.17% | 41.00% | 38.04% | 0.13% | 0.00% | 0.00% |
| 8. DEMTRAN2 | 4-CP Demand @ Generation including Wheeling (KW) | 6,445,773 | 5,102,910 | 1,342,863 | 5,102,910 | 2,642,653 | 2,451,981 | 8,276 | 0 | 0 |
| | Transmission Lines | 100.00% | 79.17% | 20.83% | 79.17% | 41.00% | 38.04% | 0.13% | 0.00% | 0.00% |
| 9. DEMTRAN4 | Transmission - SCE 500 KV Line | 100 | 0 | 100 | 0 | 0 | 0 | 0 | 0 | 0 |
| | SCE Specific | 100.00% | 0.00% | 100.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 10. DEMDIST1 | NCP Demand @ Substation Level w/losses (KW) | 6,181,490 | 6,181,490 | 0 | 6,181,490 | 3,323,537 | 2,776,499 | 35,899 | 33,222 | 12,333 |
| | Distribution Substation | 100.00% | 100.00% | 0.00% | 100.00% | 53.77% | 44.92% | 0.58% | 0.54% | 0.20% |
| 11. DEMDIST2 | NCP Demand @ Primary Line Level w/losses (KW) | 5,934,767 | 5,934,767 | 0 | 5,934,767 | 3,257,955 | 2,596,964 | 35,191 | 32,567 | 12,090 |
| | Distribution OH Primary Lines | 100.00% | 100.00% | 0.00% | 100.00% | 54.90% | 43.76% | 0.59% | 0.55% | 0.20% |
| 12. DEMDIST3 | Individual Maximum Demand @ Secondary Line Level w/losses (KW) | 4,331,559 | 4,331,559 | 0 | 4,331,559 | 3,527,660 | 761,528 | 0 | 30,900 | 11,471 |
| | Distribution OH Secondary Lines | 100.00% | 100.00% | 0.00% | 100.00% | 81.44% | 17.58% | 0.00% | 0.71% | 0.26% |
| 13. DEMDIST4 | NCP Demand @ Primary Line Level w/losses (KW) | 5,899,576 | 5,899,576 | 0 | 5,899,576 | 3,257,955 | 2,596,964 | 0 | 32,567 | 12,090 |
| | Distribution UG Primary Lines | 100.00% | 100.00% | 0.00% | 100.00% | 55.22% | 44.02% | 0.00% | 0.55% | 0.20% |
| 14. DEMDIST5 | Individual Maximum Demand @ Secondary Line Level w/losses (KW) | 4,331,559 | 4,331,559 | 0 | 4,331,559 | 3,527,660 | 761,528 | 0 | 30,900 | 11,471 |
| | Distribution UG Secondary Lines | 100.00% | 100.00% | 0.00% | 100.00% | 81.44% | 17.58% | 0.00% | 0.71% | 0.26% |
| 15. DEMDIST6 | Individual Maximum Demand @ Secondary TXF Level w/losses (KW) | 9,084,660 | 9,084,660 | 0 | 9,084,660 | 5,938,353 | 3,056,769 | 45,047 | 32,446 | 12,045 |
| | Distribution OH Line Transformers | 100.00% | 100.00% | 0.00% | 100.00% | 65.37% | 33.65% | 0.50% | 0.36% | 0.13% |

Recap Schedules: G-4, G-3

**ARIZONA PUBLIC SERVICE COMPANY**
**Cost of Service Study**
**Development of Allocation Factors**
**Adjusted Test Year Ending December 31, 2002**

| Factor | Definition and Application of Allocation Factor | Total Company | Total ACC Jurisdiction | All Other | Total Retail | Residential | General Service | Irrigation | Street Lighting | Dusk to Dawn |
|---|---|---|---|---|---|---|---|---|---|---|
| 16. DEMDIST7 | Individual Maximum Demand @ Secondary TXF Level w/losses (KW) | 9,039,623 | 9,039,623 | 0 | 9,039,623 | 5,938,353 | 3,056,779 | 0 | 32,446 | 12,045 |
| | Distribution UG Line Transformers | 100.00% | 100.00% | 0.00% | 100.00% | 65.69% | 33.82% | 0.00% | 0.36% | 0.13% |
| 17. CUSTOH1 | Weighted Customer Costs for Distribution Services ($) | 448,413 | 448,413 | 0 | 448,413 | 404,336 | 43,430 | 647 | 0 | 0 |
| | Distribution OH Services | 100.00% | 100.00% | 0.00% | 100.00% | 90.17% | 9.69% | 0.14% | 0.00% | 0.00% |
| 18. CUSTUG1 | Weighted Customer Costs for Distribution Services ($) | 456,363 | 456,363 | 0 | 456,363 | 415,485 | 40,878 | 0 | 0 | 0 |
| | Distribution UG Services | 100.00% | 100.00% | 0.00% | 100.00% | 91.04% | 8.96% | 0.00% | 0.00% | 0.00% |
| 19. DEMDIST10 | NCP Demand @ Primary Line Level w/losses (KW) | 5,934,767 | 5,934,767 | 0 | 5,934,767 | 3,257,955 | 2,596,964 | 35,191 | 32,567 | 12,090 |
| | Distribution Rents | 100.00% | 100.00% | 0.00% | 100.00% | 54.90% | 43.76% | 0.59% | 0.55% | 0.20% |
| 20. ENERGY1 | Customer Class Energy @ Generation (MWH) | 25,161,766 | 24,795,184 | 366,582 | 24,795,184 | 11,215,488 | 13,391,465 | 33,737 | 112,701 | 41,793 |
| | Production - Energy | 100.00% | 98.54% | 1.46% | 98.54% | 44.57% | 53.22% | 0.13% | 0.45% | 0.17% |
| 21. ENERGY2 | Customer Class Energy @ Generation (MWH) | 25,161,766 | 24,795,184 | 366,582 | 24,795,184 | 11,215,488 | 13,391,465 | 33,737 | 112,701 | 41,793 |
| | Production - Energy (Fuel and Purchase Power) | 100.00% | 98.54% | 1.46% | 98.54% | 44.57% | 53.22% | 0.13% | 0.45% | 0.17% |
| 22. ENERGY4 | Customer Class Energy @ Generation (MWH) | 25,161,766 | 24,795,184 | 366,582 | 24,795,184 | 11,215,488 | 13,391,465 | 33,737 | 112,701 | 41,793 |
| | Production - Energy - Ancillary Service - Must Run | 100.00% | 98.54% | 1.46% | 98.54% | 44.57% | 53.22% | 0.13% | 0.45% | 0.17% |
| 23. CUST370 | Weighted Costs for Distribution Meters ($) | 1,132,676 | 1,121,607 | 11,069 | 1,121,607 | 819,821 | 298,900 | 2,886 | 0 | 0 |
| | Distribution Meters | 100.00% | 99.02% | 0.98% | 99.02% | 72.38% | 26.39% | 0.25% | 0.00% | 0.00% |
| 24. CUST371 | Dusk to Dawn Customer Class Specific | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 1 |
| | Dusk to Dawn | 100.00% | 100.00% | 0.00% | 100.00% | 0.00% | 0.00% | 0.00% | 0.00% | 100.00% |
| 25. CUST373 | Street Lighting Customer Class Specific | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 1 | 0 |
| | Street Lighting | 100.00% | 100.00% | 0.00% | 100.00% | 0.00% | 0.00% | 0.00% | 100.00% | 0.00% |
| 26. CUSTNUM | Number of Customer Accounts | 930,373 | 929,002 | 1,371 | 929,002 | 819,821 | 100,134 | 364 | 749 | 7,934 |
| | Customer Accounts | 100.00% | 99.85% | 0.15% | 99.85% | 88.12% | 10.76% | 0.04% | 0.08% | 0.85% |
| 27. CUST910 | Number of Customer Accounts | 929,002 | 929,002 | 0 | 929,002 | 819,821 | 100,134 | 364 | 749 | 7,934 |
| | Customer Service and Information | 100.00% | 100.00% | 0.00% | 100.00% | 88.25% | 10.78% | 0.04% | 0.08% | 0.85% |
| 28. CUST916 | Number of Customer Accounts | 930,373 | 929,002 | 1,371 | 929,002 | 819,821 | 100,134 | 364 | 749 | 7,934 |
| | Sales Expense | 100.00% | 99.85% | 0.15% | 99.85% | 88.12% | 10.76% | 0.04% | 0.08% | 0.85% |
| 29. DEMREGAST | 4-CP Demand @ Generation (KW) | 5,111,775 | 5,102,910 | 8,865 | 5,102,910 | 2,642,653 | 2,451,981 | 8,276 | 0 | 0 |
| | Regulatory Asset - Demand Related | 100.00% | 99.83% | 0.17% | 99.83% | 51.70% | 47.97% | 0.16% | 0.00% | 0.00% |
| 30. ERGREGAST | Customer Class Energy @ Generation (MWH) | 25,161,766 | 24,795,184 | 366,582 | 24,795,184 | 11,215,488 | 13,391,465 | 33,737 | 112,701 | 41,793 |
| | Regulatory Asset - Energy Related | 100.00% | 98.54% | 1.46% | 98.54% | 44.57% | 53.22% | 0.13% | 0.45% | 0.17% |
| 31. ERGSYSBEN | Customer Class Energy @ Generation (MWH) | 25,161,766 | 24,795,184 | 366,582 | 24,795,184 | 11,215,488 | 13,391,465 | 33,737 | 112,701 | 41,793 |
| | System Benefits - Energy Related | 100.00% | 98.54% | 1.46% | 98.54% | 44.57% | 53.22% | 0.13% | 0.45% | 0.17% |

Recap Schedules: G-4, G-3

**ARIZONA PUBLIC SERVICE COMPANY**
**Cost of Service Study**
**Development of Allocation Factors**
**Adjusted Test Year Ending December 31, 2002**

| Factor | Definition and Application of Allocation Factor | General Service | Small General Service | Medium General Service | Large General Service | Extra-Large General Service | Residential | Residential E-10 | Residential E-12 | Residential EC-1 | Residential ET-1 | Residential ECT-1 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. DEMPROD1 | 4-CP Demand @ Generation (KW) | 2,451,981 | 828,460 | 994,764 | 285,615 | 343,142 | 2,642,653 | 232,966 | 766,305 | 141,521 | 1,240,307 | 261,554 |
| | Production Demand | 47.97% | 16.21% | 19.46% | 5.59% | 6.71% | 51.70% | 4.56% | 14.99% | 2.77% | 24.26% | 5.12% |
| 2. DEMPROD2 | 4-CP Demand @ Generation (KW) | 2,451,981 | 828,460 | 994,764 | 285,615 | 343,142 | 2,642,653 | 232,966 | 766,305 | 141,521 | 1,240,307 | 261,554 |
| | Production - Ancillary Service - Regulation | 47.97% | 16.21% | 19.46% | 5.59% | 6.71% | 51.70% | 4.56% | 14.99% | 2.77% | 24.26% | 5.12% |
| 3. DEMPROD3 | 4-CP Demand @ Generation (KW) | 2,451,981 | 828,460 | 994,764 | 285,615 | 343,142 | 2,642,653 | 232,966 | 766,305 | 141,521 | 1,240,307 | 261,554 |
| | Production - Ancillary Service - Spinning Reserve | 47.97% | 16.21% | 19.46% | 5.59% | 6.71% | 51.70% | 4.56% | 14.99% | 2.77% | 24.26% | 5.12% |
| 4. DEMPROD4 | 4-CP Demand @ Generation (KW) | 2,451,981 | 828,460 | 994,764 | 285,615 | 343,142 | 2,642,653 | 232,966 | 766,305 | 141,521 | 1,240,307 | 261,554 |
| | Production - Ancillary Service - Ready Reserve | 47.97% | 16.21% | 19.46% | 5.59% | 6.71% | 51.70% | 4.56% | 14.99% | 2.77% | 24.26% | 5.12% |
| 5. DEMPROD6 | 4-CP Demand @ Generation (KW) | 2,451,981 | 828,460 | 994,764 | 285,615 | 343,142 | 2,642,653 | 232,966 | 766,305 | 141,521 | 1,240,307 | 261,554 |
| | Production - Ancillary Service - Scheduling & Dispatch | 47.97% | 16.21% | 19.46% | 5.59% | 6.71% | 51.70% | 4.56% | 14.99% | 2.77% | 24.26% | 5.12% |
| 6. DEMPROD7 | 4-CP Demand @ Generation (KW) | 2,451,981 | 828,460 | 994,764 | 285,615 | 343,142 | 2,642,653 | 232,966 | 766,305 | 141,521 | 1,240,307 | 261,554 |
| | Production - Ancillary Service - Must Run | 47.97% | 16.21% | 19.46% | 5.59% | 6.71% | 51.70% | 4.56% | 14.99% | 2.77% | 24.26% | 5.12% |
| 7. DEMTRAN1 | 4-CP Demand @ Generation including Wheeling (KW) | 2,451,981 | 828,460 | 994,764 | 285,615 | 343,142 | 2,642,653 | 232,966 | 766,305 | 141,521 | 1,240,307 | 261,554 |
| | Transmission Substation | 38.04% | 12.85% | 15.43% | 4.43% | 5.32% | 41.00% | 3.61% | 11.89% | 2.20% | 19.24% | 4.06% |
| 8. DEMTRAN2 | 4-CP Demand @ Generation including Wheeling (KW) | 2,451,981 | 828,460 | 994,764 | 285,615 | 343,142 | 2,642,653 | 232,966 | 766,305 | 141,521 | 1,240,307 | 261,554 |
| | Transmission Lines | 38.04% | 12.85% | 15.43% | 4.43% | 5.32% | 41.00% | 3.61% | 11.89% | 2.20% | 19.24% | 4.06% |
| 9. DEMTRAN4 | Transmission - SCE 500 KV Line | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | SCE Specific | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 10. DEMDIST1 | NCP Demand @ Substation Level w/losses (KW) | 2,776,499 | 970,264 | 1,184,158 | 283,088 | 338,989 | 3,323,537 | 306,035 | 965,170 | 155,972 | 1,550,013 | 346,347 |
| | Distribution Substation | 44.92% | 15.70% | 19.16% | 4.58% | 5.48% | 53.77% | 4.95% | 15.61% | 2.52% | 25.08% | 5.60% |
| 11. DEMDIST2 | NCP Demand @ Primary Line Level w/losses (KW) | 2,596,964 | 950,468 | 1,157,321 | 270,617 | 218,558 | 3,257,955 | 299,996 | 946,125 | 152,894 | 1,519,427 | 339,513 |
| | Distribution OH Primary Lines | 43.76% | 16.02% | 19.50% | 4.56% | 3.68% | 54.90% | 5.05% | 15.94% | 2.58% | 25.60% | 5.72% |
| 12. DEMDIST3 | Individual Maximum Demand @ Secondary Line Level w/losses (KW) | 761,528 | 761,528 | 0 | 0 | 0 | 3,527,660 | 328,650 | 1,249,580 | 137,693 | 1,519,087 | 292,650 |
| | Distribution OH Secondary Lines | 17.58% | 17.58% | 0.00% | 0.00% | 0.00% | 81.44% | 7.59% | 28.85% | 3.18% | 35.07% | 6.76% |
| 13. DEMDIST4 | NCP Demand @ Primary Line Level w/losses (KW) | 2,596,964 | 950,468 | 1,157,321 | 270,617 | 218,558 | 3,257,955 | 299,996 | 946,125 | 152,894 | 1,519,427 | 339,513 |
| | Distribution UG Primary Lines | 44.02% | 16.11% | 19.62% | 4.59% | 3.70% | 55.22% | 5.09% | 16.04% | 2.59% | 25.75% | 5.75% |
| 14. DEMDIST5 | Individual Maximum Demand @ Secondary Line Level w/losses (KW) | 761,528 | 761,528 | 0 | 0 | 0 | 3,527,660 | 328,650 | 1,249,580 | 137,693 | 1,519,087 | 292,650 |
| | Distribution UG Secondary Lines | 17.58% | 17.58% | 0.00% | 0.00% | 0.00% | 81.44% | 7.59% | 28.85% | 3.18% | 35.07% | 6.76% |
| 15. DEMDIST6 | Individual Maximum Demand @ Secondary TXF Level w/losses (KW) | 3,056,769 | 1,300,052 | 1,363,985 | 257,322 | 135,410 | 5,938,353 | 553,239 | 2,103,504 | 231,787 | 2,557,185 | 492,638 |
| | Distribution OH Line Transformers | 33.65% | 14.31% | 15.01% | 2.83% | 1.49% | 65.37% | 6.09% | 23.15% | 2.55% | 28.15% | 5.42% |

Recap Schedules: G-4, G-3

**ARIZONA PUBLIC SERVICE COMPANY**
**Cost of Service Study**
**Development of Allocation Factors**
**Adjusted Test Year Ending December 31, 2002**

| Factor | Definition and Application of Allocation Factor | General Service | Small General Service | Medium General Service | Large General Service | Extra-Large General Service | Residential | Residential E-10 | Residential E-12 | Residential EC-1 | Residential ET-1 | Residential ECT-1 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 16. DEMDIST7 | Individual Maximum Demand @ Secondary TXF Level w/losses (KW) | 3,056,779 | 1,300,052 | 1,363,985 | 257,332 | 135,410 | 5,938,353 | 553,239 | 2,103,504 | 231,787 | 2,557,185 | 492,638 |
| | Distribution UG Line Transformers | 33.82% | 14.38% | 15.09% | 2.85% | 1.50% | 65.69% | 6.12% | 23.27% | 2.56% | 28.29% | 5.45% |
| 17. CUSTOH1 | Weighted Customer Costs for Distribution Services ($) | 43,430 | 39,828 | 3,602 | 0 | 0 | 819,821 | 93,834 | 381,583 | 24,806 | 276,670 | 42,928 |
| | Distribution OH Services | 9.69% | 8.88% | 0.80% | 0.00% | 0.00% | 182.83% | 20.93% | 85.10% | 5.53% | 61.70% | 9.57% |
| 18. CUSTUG1 | Weighted Customer Costs for Distribution Services ($) | 40,878 | 33,450 | 4,064 | 2,828 | 536 | 819,821 | 93,834 | 381,583 | 24,806 | 276,670 | 42,928 |
| | Distribution UG Services | 8.96% | 7.33% | 0.89% | 0.62% | 0.12% | 179.64% | 20.56% | 83.61% | 5.44% | 60.62% | 9.41% |
| 19. DEMDIST10 | NCP Demand @ Primary Line Level w/losses (KW) | 2,596,964 | 950,468 | 1,157,321 | 270,617 | 218,558 | 3,257,955 | 299,996 | 946,125 | 152,894 | 1,519,427 | 339,513 |
| | Distribution Rents | 43.76% | 16.02% | 19.50% | 4.56% | 3.68% | 54.90% | 5.05% | 15.94% | 2.58% | 25.60% | 5.72% |
| 20. ENERGY1 | Customer Class Energy @ Generation (MWH) | 13,391,465 | 3,766,696 | 5,288,514 | 1,754,953 | 2,581,302 | 11,215,488 | 1,020,291 | 3,356,182 | 635,131 | 4,917,386 | 1,286,498 |
| | Production - Energy | 53.22% | 14.97% | 21.02% | 6.97% | 10.26% | 44.57% | 4.05% | 13.34% | 2.52% | 19.54% | 5.11% |
| 21. ENERGY2 | Customer Class Energy @ Generation (MWH) | 13,391,465 | 3,766,696 | 5,288,514 | 1,754,953 | 2,581,302 | 11,215,488 | 1,020,291 | 3,356,182 | 635,131 | 4,917,386 | 1,286,498 |
| | Production - Energy (Fuel and Purchase Power) | 53.22% | 14.97% | 21.02% | 6.97% | 10.26% | 44.57% | 4.05% | 13.34% | 2.52% | 19.54% | 5.11% |
| 22. ENERGY4 | Customer Class Energy @ Generation (MWH) | 13,391,465 | 3,766,696 | 5,288,514 | 1,754,953 | 2,581,302 | 11,215,488 | 1,020,291 | 3,356,182 | 635,131 | 4,917,386 | 1,286,498 |
| | Production - Energy - Ancillary Service - Must Run | 53.22% | 14.97% | 21.02% | 6.97% | 10.26% | 44.57% | 4.05% | 13.34% | 2.52% | 19.54% | 5.11% |
| 23. CUST370 | Weighted Costs for Distribution Meters ($) | 298,900 | 259,684 | 32,608 | 3,818 | 2,790 | 560,930 | 42,736 | 173,790 | 24,806 | 276,670 | 42,928 |
| | Distribution Meters | 26.39% | 22.93% | 2.88% | 0.34% | 0.25% | 49.52% | 3.77% | 15.34% | 2.19% | 24.43% | 3.79% |
| 24. CUST371 | Dusk to Dawn Customer Class Specific | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Dusk to Dawn | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 25. CUST373 | Street Lighting Customer Class Specific | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Street Lighting | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 26. CUSTNUM | Number of Customer Accounts | 100,134 | 95,717 | 4,112 | 244 | 61 | 819,821 | 93,834 | 381,583 | 24,806 | 276,670 | 42,928 |
| | Customer Accounts | 10.76% | 10.29% | 0.44% | 0.03% | 0.01% | 88.12% | 10.09% | 41.01% | 2.67% | 29.74% | 4.61% |
| 27. CUST910 | Number of Customer Accounts | 100,134 | 95,717 | 4,112 | 244 | 61 | 819,821 | 93,834 | 381,583 | 24,806 | 276,670 | 42,928 |
| | Customer Service and Information | 10.78% | 10.30% | 0.44% | 0.03% | 0.01% | 88.25% | 10.10% | 41.07% | 2.67% | 29.78% | 4.62% |
| 28. CUST916 | Number of Customer Accounts | 100,134 | 95,717 | 4,112 | 244 | 61 | 819,821 | 93,834 | 381,583 | 24,806 | 276,670 | 42,928 |
| | Sales Expense | 10.76% | 10.29% | 0.44% | 0.03% | 0.01% | 88.12% | 10.09% | 41.01% | 2.67% | 29.74% | 4.61% |
| 29. DEMREGAST | 4-CP Demand @ Generation (KW) | 2,451,981 | 828,460 | 994,764 | 285,615 | 343,142 | 2,642,653 | 232,966 | 766,305 | 141,521 | 1,240,307 | 261,554 |
| | Regulatory Asset - Demand Related | 47.97% | 16.21% | 19.46% | 5.59% | 6.71% | 51.70% | 4.56% | 14.99% | 2.77% | 24.26% | 5.12% |
| 30. ERGREGAST | Customer Class Energy @ Generation (MWH) | 13,391,465 | 3,766,696 | 5,288,514 | 1,754,953 | 2,581,302 | 11,215,488 | 1,020,291 | 3,356,182 | 635,131 | 4,917,386 | 1,286,498 |
| | Regulatory Asset - Energy Related | 53.22% | 14.97% | 21.02% | 6.97% | 10.26% | 44.57% | 4.05% | 13.34% | 2.52% | 19.54% | 5.11% |
| 31. ERGSYSBEN | Customer Class Energy @ Generation (MWH) | 13,391,465 | 3,766,696 | 5,288,514 | 1,754,953 | 2,581,302 | 11,215,488 | 1,020,291 | 3,356,182 | 635,131 | 4,917,386 | 1,286,498 |
| | System Benefits - Energy Related | 53.22% | 14.97% | 21.02% | 6.97% | 10.26% | 44.57% | 4.05% | 13.34% | 2.52% | 19.54% | 5.11% |

Recap Schedules: G-4, G-3

H-1

# ARIZONA PUBLIC SERVICE COMPANY
## SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
## PRESENT AND PROPOSED RATES
## TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

| | | Base Revenues in the Test Year (a) | | Proposed Increase (b) | | | | |
|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | |
| Line No. | Customer Classification | Present Rates [1] ($000) | Proposed Rates [3) 4)] ($000) | Amount ($000) (B) - (A) | % (C) / (A) | Proposed CRCC [2] ($000) | Proposed Increase with CRCC % [(E) + (C)] / (A) | Line No. |
| 1 | Residential | 889,898 | 972,747 | 82,849 | 9.31% | 3,737 | 9.73% | 1 |
| 2 | General Service | 883,595 | 965,868 | 82,273 | 9.31% | 4,485 | 9.82% | 2 |
| 3 | Irrigation | 2,099 | 2,295 | 196 | 9.34% | 11 | 9.86% | 3 |
| 4 | Outdoor Lighting | 10,794 | 11,799 | 1,005 | 9.31% | 36 | 9.64% | 4 |
| 5 | Dusk to Dawn Lighting Service | 5,198 | 5,682 | 484 | 9.31% | 14 | 9.58% | 5 |
| 6 | Total Sales to Ultimate Retail Customers | 1,791,584 | 1,958,391 | 166,807 | 9.31% | 8,283 | 9.77% | 6 |

(a) Supporting Schedules: H-2

(b) Recap Schedules: A-1

NOTES TO SCHEDULE:

1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments such as rate decreases and removal of franchise fees from base rates.
2) The CRCC is the Competition Rules Compliance Charge as proposed in ACC Docket No. E-01345A-02-0403. The proposed CRCC will be in place for five years.
3) Please note that the Proposed Increase shown on this schedule does not directly match the Proposed Increase on Schedule H-2 for the General Service and Irrigation classes. Schedule H-2 assumes customer migration from Irrigation to General Service due to more favorable rates. The total proposed revenue for both Irrigation and General Service classes on these two schedules match.
4) The total proposed revenue for both Outdoor Lighting and Dusk to Dawn classes on this schedule matches the total proposed revenue for both classes on Schedule H-2.

H-2

# ARIZONA PUBLIC SERVICE COMPANY
## ANALYSIS OF BASE REVENUES BY DETAILED CLASS
## TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Proposed Rates (a) | | | Proposed Increase | | |
| Line No. | Customer Classification and Current Rate Designation | Average Number of Customers | MWh Sales | Average Annual kWh Usage per Customer | Base Revenues under Present Rates ($000) | Proposed Rate Designation | Base Revenues ($000) | CRCC ($000) | Amount ($000) | % | Line No. |
| | | | | [(C) x 1000] / (B) | | | | (C) x 0.000353 | [(G) + (H)] - (E) | (I) / (E) | |
| 1 | Residential | | | | | | | | | | 1 |
| 2 | E-10 | 94,544 | 904,512 | 9,567 | 78,922 | E-10 Step 1 | 88,530 | 319 | 9,927 | 12.58% | 2 |
| 3 | | | | | | E-12 | 1,586 | | 1,586 | 1.79% | 3 |
| 4 | E-12 | 375,020 | 3,186,522 | 8,497 | 301,433 | E-12 | 320,161 | 1,125 | 19,853 | 6.59% | 4 |
| 5 | EC-1 | 24,951 | 568,530 | 22,786 | 42,753 | ECT-1R | 49,160 | 201 | 6,608 | 15.46% | 5 |
| 6 | ET-1 | 277,112 | 4,721,930 | 17,040 | 381,113 | ET-1 | 422,085 | 1,667 | 42,639 | 11.19% | 6 |
| 7 | ECT-1R | 43,117 | 1,205,109 | 27,950 | 85,677 | ECT-1R | 91,225 | 425 | 5,973 | 6.97% | 7 |
| 8 | DA-R1 | - | - | - | - | DA-R1 | | Rate Cancelled | | | 8 |
| 9 | Total Residential | 814,744 | 10,586,603 | 12,994 | 889,898 | | 972,747 | 3,737 | 86,586 | 9.73% | 9 |
| 10 | General Service | | | | | | | | | | 10 |
| 11 | E-20 | 339 | 36,907 | 108,870 | 3,009 | E-20 | 3,430 | 13 | 434 | 14.42% | 11 |
| 12 | E-21 | 20 | 1,099 | 54,950 | 83 | E-32TOU | 101 | - | 18 | 21.69% | 12 |
| 13 | E-21 | 9 | 641 | 71,222 | 54 | E-32 | 67 | - | 13 | 24.07% | 13 |
| 14 | E-22 | 5 | 4,899 | 979,800 | 362 | E-32TOU | 352 | 2 | (8) | -2.21% | 14 |
| 15 | E-22 | 9 | 2,307 | 256,333 | 202 | E-32 | 295 | 1 | 94 | 46.53% | 15 |
| 16 | E-23 | 97 | 31,308 | 322,763 | 2,245 | E-32TOU | 2,319 | 11 | 85 | 3.79% | 16 |
| 17 | E-23 | 51 | 14,655 | 287,353 | 1,045 | E-32 | 1,046 | 5 | 6 | 0.57% | 17 |
| 18 | E-24 | 29 | 118,278 | 4,078,552 | 6,747 | E-32TOU | 7,777 | 42 | 1,072 | 15.89% | 18 |
| 19 | E-24 | 19 | 59,661 | 3,140,053 | 3,448 | E-32 | 3,667 | 21 | 240 | 6.96% | 19 |
| 20 | E-30 | 4,023 | 6,721 | 1,671 | 973 | E-30 | 1,065 | 2 | 94 | 9.66% | 20 |
| 21 | E-32, E-32R, E-53, E-54 | 94,180 | 9,551,113 | 101,413 | 716,195 | E-32, E-32R, E-53, E-54 | 782,311 | 3,372 | 69,488 | 9.70% | 21 |
| 22 | E-34 | 41 | 1,232,771 | 30,067,585 | 66,458 | E-34 | 72,904 | 435 | 6,881 | 10.35% | 22 |
| 23 | E-35 | 19 | 1,217,184 | 64,062,316 | 57,357 | E-35 | 62,926 | 430 | 5,999 | 10.46% | 23 |
| 24 | E-38, E-38-8T, E-38TOW | 88 | 7,320 | 83,182 | 471 | E-221, E-221-8T, E-221TOW | 541 | 3 | 73 | 15.50% | 24 |
| 25 | E-40 | 2 | 1 | 500 | 2 | E-40 | 2 | - | | 9.33% | 25 |
| 26 | E-51 | 4 | 18,135 | 4,533,750 | 1,158 | E-51 | 1,282 | 6 | 130 | 11.23% | 26 |
| 27 | E-221, E-221-8T, E-221TOW | 1,272 | 302,679 | 237,955 | 20,423 | E-221, E-221-8T, E-221TOW | 22,322 | 107 | 2,006 | 9.82% | 27 |
| 28 | Contracts | 3 | 100,373 | 33,457,667 | 3,363 | Contracts | 3,485 | 35 | 157 | 4.67% | 28 |
| 29 | DA-GS1,10,11,12,13 | - | - | - | - | DA-GS1,10,11,12,13 | | - - - Rates Cancelled - - - | | | 29 |
| 30 | Total General Service | 100,210 | 12,706,052 | 126,794 | 883,595 | | 965,892 | 4,485 | 86,782 | 9.82% | 30 |

Supporting Schedules:

Recap Schedules: (a) H-1

# ARIZONA PUBLIC SERVICE COMPANY
## ANALYSIS OF BASE REVENUES BY DETAILED CLASS
## TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

| Line No. | (A) Customer Classification and Current Rate Designation | (B) Average Number of Customers | (C) MWh Sales | (D) Average Annual kWh Usage per Customer [(C) x 1000] / (B) | (E) Base Revenues under Present Rates ($000) | (F) Proposed Rates (a) Proposed Rate Designation | (G) Proposed Rates (a) Base Revenues ($000) | (H) Proposed Rates (a) CRCC ($000) (C) x 0.000353 | (I) Proposed Increase Amount ($000) [(G) + (H)] - (E) | (J) Proposed Increase % (I) / (E) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 31 | Irrigation | | | | | | | | | | 31 |
| 32 | E-32 | 135 | 11,308 | 83,763 | 822 | E-221 | 805 | 4 | (13) | -1.58% | 32 |
| 33 | E-38, E-38-8T, E-38TOW | 69 | 7,786 | 112,841 | 476 | E-221, E-221-8T, E-221TOW | 569 | 3 | 96 | 20.17% | 33 |
| 34 | E-221, E-221-8T, E-221TOW | 128 | 11,747 | 91,773 | 801 | E-221, E-221-8T, E-221TOW | 897 | 4 | 100 | 12.48% | 34 |
| 35 | Total Irrigation | 332 | 30,841 | 92,895 | 2,099 | | 2,271 | 11 | 183 | 8.72% | 35 |
| 36 | Outdoor Lighting | | | | | | | | | | 36 |
| 37 | E-32 | 4 | 59 | 14,750 | 6 | E-32 | 6 | - | 0 | 5.66% | 37 |
| 38 | E-58 | 517 | 21,744 | 42,058 | 4,552 | E-58 | 4,976 | 8 | 432 | 9.49% | 38 |
| 39 | E-59 | 177 | 64,993 | 367,192 | 5,509 | E-59 | 6,022 | 23 | 536 | 9.73% | 39 |
| 40 | E-67 | 231 | 4,579 | 19,823 | 156 | E-67 | 186 | 2 | 32 | 20.51% | 40 |
| 41 | Contracts | 24 | 9,366 | 390,250 | 571 | Contracts | 624 | 3 | 56 | 9.81% | 41 |
| 42 | Total Outdoor Lighting | 953 | 100,741 | 105,709 | 10,794 | | 11,814 | 36 | 1,056 | 9.79% | 42 |
| 43 | Dusk to Dawn Lighting Service | See Note 4) | 38,475 | See Note 4) | 5,198 | | 5,667 | 14 | 483 | 9.29% | 43 |
| 44 | Total Sales to Ultimate Retail Customers | 916,239 | 23,462,712 | 25,608 | 1,791,584 | | 1,958,391 | 8,283 | 175,090 | 9.77% | 44 |

Supporting Schedules:

Recap Schedules: (a) H-1

NOTES TO SCHEDULE:

1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments such as rate decreases and removal of franchise fees from base rates.
2) The CRCC is the Competition Rules Compliance Charge as proposed in ACC Docket No. E-01345A-02-0403. The proposed CRCC will be in place for five years.
3) The following rate schedules will not change: Solar Rate Schedules, EPR Rate Schedules, Share the Light Rate Schedules, Rate Schedules E-36, E-52, and E-55, and Rate Schedules E-3 and E-4.
4) Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.
5) Reclassification of revenue in Irrigation and General Service classes results in class revenue shifts. The total proposed revenue for both Irrigation and General Service classes on this schedule matches the total proposed revenue for both classes on Schedule H-1.
6) The total proposed revenue for both Outdoor Lighting and Dusk to Dawn classes on this schedule matches the total proposed revenue for both classes on Schedule H-1.

H-3

**ARIZONA PUBLIC SERVICE COMPANY**

**CHANGES IN REPRESENTATIVE RATE SCHEDULES**
**COMPARISON OF PRESENT AND PROPOSED RATES**

**TEST YEAR ENDING DECEMBER 31, 2002**

| Line No. | (A) Rate Schedule | (B) Description | (C) Season | (D) Present Rates Block | (E) Present Rates Rates | (F) | (G) Proposed Rates Block | (H) Proposed Rates Rates | (I) | (J) Proposed Rates with Franchise Fees (H) x 0.0144 | (K) | (L) Change (J) - (E) | (M) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | E-3 | Residential Energy | | NO CHANGE | | | NO CHANGE | | | | | | | 1 |
| 2 | | Support Program | | | | | | | | | | | | 2 |
| 3 | E-4 | Residential Energy | | NO CHANGE | | | NO CHANGE | | | | | | | 3 |
| 4 | | Support Program | | | | | | | | | | | | 4 |
| 5 | E-10 | Residential Service | Summer | Basic Service Charge | $ 7.50 | /mo | | | | | | N/A | | 5 |
| 6 | **STEP 1** | | | | | | Basic Service Charge | $ 0.271 | /day | $ 0.275 | /day | N/A | | 6 |
| 7 | | | | First 400 kWh | 0.06682 | /kWh | First 400 kWh | 0.07332 | /kWh | 0.07438 | /kWh | 0.00756 | /kWh | 7 |
| 8 | | | | Next 400 kWh | 0.09189 | /kWh | Next 400 kWh | 0.10083 | /kWh | 0.10228 | /kWh | 0.01039 | /kWh | 8 |
| 9 | | | | All additional kWh | 0.09440 | /kWh | All additional kWh | 0.10358 | /kWh | 0.10507 | /kWh | 0.01067 | /kWh | 9 |
| 10 | | | Winter | Basic Service Charge | $ 7.50 | /mo | | | | | | N/A | | 10 |
| 11 | | | | | | | Basic Service Charge | $ 0.271 | /day | $ 0.275 | /day | N/A | | 11 |
| 12 | | | | All kWh | 0.07609 | /kWh | All kWh | 0.08349 | /kWh | 0.08469 | /kWh | 0.00860 | /kWh | 12 |
| 13 | | | Sum & Win | Minimum | $ 7.50 | /mo | | | | | | N/A | | 13 |
| 14 | E-10 | Residential Service | | | | | Basic Service Charge | $ 0.411 | /day | $ 0.417 | /day | N/A | | 14 |
| 15 | **STEP 2** | | | | | | First 400 kWh | 0.08640 | /kWh | 0.08764 | /kWh | N/A | | 15 |
| 16 | (Move to | | | | | | Next 400 kWh | 0.08640 | /kWh | 0.08764 | /kWh | N/A | | 16 |
| 17 | E-12) | | | | | | All additional kWh | 0.11006 | /kWh | 0.11164 | /kWh | N/A | | 17 |
| 18 | | | | | | | Basic Service Charge | $ 0.411 | /day | $ 0.417 | /day | N/A | | 18 |
| 19 | | | | | | | All kWh | 0.07004 | /kWh | 0.07105 | /kWh | N/A | | 19 |
| 20 | E-12 | Residential Service | Summer | Basic Service Charge | $ 7.50 | /mo | | | | | | N/A | | 20 |
| 21 | | | | | | | Basic Service Charge | $ 0.411 | /day | $ 0.417 | /day | N/A | | 21 |
| 22 | | | | First 400 kWh | 0.07376 | /kWh | First 400 kWh | 0.08640 | /kWh | 0.08764 | /kWh | 0.01388 | /kWh | 22 |
| 23 | | | | Next 400 kWh | 0.10281 | /kWh | Next 400 kWh | 0.08640 | /kWh | 0.08764 | /kWh | (0.01517) | /kWh | 23 |
| 24 | | | | All additional kWh | 0.11991 | /kWh | All additional kWh | 0.11006 | /kWh | 0.11164 | /kWh | (0.00827) | /kWh | 24 |
| 25 | | | Winter | Basic Service Charge | $ 7.50 | /mo | | | | | | N/A | | 25 |
| 26 | | | | | | | Basic Service Charge | $ 0.411 | /day | $ 0.417 | /day | N/A | | 26 |
| 27 | | | | All kWh | 0.07394 | /kWh | All kWh | 0.07004 | /kWh | 0.07105 | /kWh | (0.00289) | /kWh | 27 |
| 28 | | | Sum & Win | Minimum | $ 7.50 | /mo | | | | | | N/A | | 28 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

## ARIZONA PUBLIC SERVICE COMPANY

## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND PROPOSED RATES

## TEST YEAR ENDING DECEMBER 31, 2002

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Present Rates | | | Proposed Rates | | | Proposed Rates with | | | | |
| Line No. | Rate Schedule | Description | Season | Block | Rates | | Block | Rates | | Franchise Fees (H) x 0.0144 | | Change (J) - (E) | | Line No. |
| 29 | EC-1 | Residential Service | Summer | Basic Service Charge | $ 10.00 | /mo | | | | | | N/A | | 29 |
| 30 | (Move to | With Demand Charge | | | | | Basic Service Charge | $ 0.493 | /day | $ 0.500 | /day | N/A | | 30 |
| 31 | ECT-1R) | | | All kW | 9.84 | /kW | All On-Peak kW | 11.00 | /kW | 11.16 | /kW | 1.32 | /kW | 31 |
| 32 | | | | All kWh (demand cap) | 0.07872 | /kWh | | | | | | N/A | | 32 |
| 33 | | | | All kWh | 0.03827 | /kWh | | | | | | N/A | | 33 |
| 34 | | | | | | | All On-Peak kWh | 0.05204 | /kWh | 0.05279 | /kWh | N/A | | 34 |
| 35 | | | | | | | All Off-Peak kWh | 0.03202 | /kWh | 0.03248 | /kWh | N/A | | 35 |
| 36 | | | Winter | Basic Service Charge | $ 10.00 | /mo | | | | | | N/A | | 36 |
| 37 | | | | | | | Basic Service Charge | $ 0.493 | /day | $ 0.500 | /day | N/A | | 37 |
| 38 | | | | All kW | 7.06 | /kW | All kW | 8.00 | /kW | 8.12 | /kW | 1.06 | /kW | 38 |
| 39 | | | | All kWh (demand cap) | 0.05648 | /kWh | | | | | | N/A | | 39 |
| 40 | | | | All kWh | 0.03176 | /kWh | | | | | | N/A | | 40 |
| 41 | | | | | | | All kWh | 0.03025 | /kWh | 0.03069 | /kWh | N/A | | 41 |
| 42 | | | Sum & Win | Minimum | $ 10.00 | /mo | | | | | | N/A | | 42 |
| 43 | ET-1 | Residential Service | Summer | Basic Service Charge | $ 15.00 | /mo | | | | | | N/A | | 43 |
| 44 | | Time of Use | | | | | Basic Service Charge | $ 0.485 | /day | $ 0.492 | /day | N/A | | 44 |
| 45 | | | | All On-Peak kWh | 0.12815 | /kWh | All On-Peak kWh | 0.12151 | /kWh | 0.12326 | /kWh | (0.00489) | /kWh | 45 |
| 46 | | | | All Off-Peak kWh | 0.04129 | /kWh | All Off-Peak kWh | 0.06121 | /kWh | 0.06209 | /kWh | 0.02080 | /kWh | 46 |
| 47 | | | Winter | Basic Service Charge | $ 15.00 | /mo | | | | | | N/A | | 47 |
| 48 | | | | | | | Basic Service Charge | $ 0.485 | /day | $ 0.492 | /day | N/A | | 48 |
| 49 | | | | All On-Peak kWh | 0.10656 | /kWh | | | | | | N/A | | 49 |
| 50 | | | | All Off-Peak kWh | 0.04129 | /kWh | | | | | | N/A | | 50 |
| 51 | | | | | | | All kWh | 0.06784 | /kWh | 0.06882 | /kWh | N/A | | 51 |
| 52 | | | Sum & Win | Minimum | $ 15.00 | /mo | | | | | | N/A | | 52 |
| 53 | ECT-1R | Residential Service | Summer | Basic Service Charge | $ 15.00 | /mo | | | | | | N/A | | 53 |
| 54 | | Time of Use with | | | | | Basic Service Charge | $ 0.493 | /day | $ 0.500 | /day | N/A | | 54 |
| 55 | | Demand Charge | | All On-Peak kW | 11.33 | /kW | All On-Peak kW | 11.00 | /kW | 11.16 | /kW | (0.17) | /kW | 55 |
| 56 | | | | All kWh (demand cap) | 0.08912 | /kWh | | | | | | N/A | | 56 |
| 57 | | | | All On-Peak kWh | 0.04572 | /kWh | All On-Peak kWh | 0.05204 | /kWh | 0.05279 | /kWh | 0.00707 | /kWh | 57 |
| 58 | | | | All Off-Peak kWh | 0.02543 | /kWh | All Off-Peak kWh | 0.03202 | /kWh | 0.03248 | /kWh | 0.00705 | /kWh | 58 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

**ARIZONA PUBLIC SERVICE COMPANY**

**CHANGES IN REPRESENTATIVE RATE SCHEDULES**
**COMPARISON OF PRESENT AND PROPOSED RATES**

**TEST YEAR ENDING DECEMBER 31, 2002**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Present Rates | | | Proposed Rates | | | Proposed Rates with | | | | |
| Line No. | Rate Schedule | Description | Season | Block | Rates | | Block | Rates | | Franchise Fees (H) x 0.0144 | | Change (J) - (E) | | Line No. |
| 59 | ECT-1R | | Winter | Basic Service Charge | $ 15.00 | /mo | | | | | | N/A | | 59 |
| 60 | (cont) | | | | | | Basic Service Charge | $ 0.493 | /day | $ 0.500 | /day | N/A | | 60 |
| 61 | | | | All On-Peak kW | 8.11 | /kW | All kW | 8.00 | /kW | 8.12 | /kW | 0.01 | /kW | 61 |
| 62 | | | | All kWh (demand cap) | 0.06488 | /kWh | | | | | | N/A | | 62 |
| 63 | | | | All On-Peak kWh | 0.03618 | /kWh | | | | | | N/A | | 63 |
| 64 | | | | All Off-Peak kWh | 0.02543 | /kWh | | | | | | N/A | | 64 |
| 65 | | | | | | | All kWh | 0.03025 | /kWh | 0.03069 | /kWh | N/A | | 65 |
| 66 | | | Sum & Win | Minimum | $ 15.00 | /mo | | | | | | N/A | | 66 |
| 67 | E-20 | General Service | Summer | Basic Service Charge | $ 27.00 | /mo | | | | | | N/A | | 67 |
| 68 | | Time of Use for | | | | | BSC: Self-Contained Meters | $ 0.600 | /day | $ 0.609 | /day | N/A | | 68 |
| 69 | | Religious Houses of | | | | | BSC: Instrument-rated Meters | $ 1.134 | /day | $ 1.150 | /day | N/A | | 69 |
| 70 | | Worship | | All On-Peak kW | 1.93 | /kW | All On-Peak kW | 2.00 | /kW | 2.03 | /kW | 0.10 | /kW | 70 |
| 71 | | | | Excess Off-Peak kW | 0.97 | /kW | Excess Off-Peak kW | 1.00 | /kW | 1.01 | /kW | 0.04 | /kW | 71 |
| 72 | | | | All On-Peak kWh | 0.11605 | /kWh | All On-Peak kWh | 0.10122 | /kWh | 0.10268 | /kWh | (0.01337) | /kWh | 72 |
| 73 | | | | All Off-Peak kWh | 0.05605 | /kWh | All Off-Peak kWh | 0.06873 | /kWh | 0.06972 | /kWh | 0.01367 | /kWh | 73 |
| 74 | | | Winter | Basic Service Charge | $ 27.00 | /mo | | | | | | N/A | | 74 |
| 75 | | | | | | | BSC: Self-Contained Meters | $ 0.600 | /day | $ 0.609 | /day | N/A | | 75 |
| 76 | | | | | | | BSC: Instrument-rated Meters | $ 1.134 | /day | $ 1.150 | /day | N/A | | 76 |
| 77 | | | | All On-Peak kW | 1.74 | /kW | All On-Peak kW | 2.00 | /kW | 2.03 | /kW | 0.29 | /kW | 77 |
| 78 | | | | Excess Off-Peak kW | 0.87 | /kW | Excess Off-Peak kW | 1.00 | /kW | 1.01 | /kW | 0.14 | /kW | 78 |
| 79 | | | | All On-Peak kWh | 0.10205 | /kWh | | | | | | N/A | | 79 |
| 80 | | | | All Off-Peak kWh | 0.05024 | /kWh | | | | | | N/A | | 80 |
| 81 | | | | | | | All kWh | 0.07638 | /kWh | 0.07748 | /kWh | N/A | | 81 |
| 82 | | | Sum & Win | Minimum - Basic Service Charge | $ 20.00 | /mo | | | | | | N/A | | 82 |
| 83 | | | | | | | Minimum: Self-Contained Meters | $ 0.600 | /day | $ 0.609 | /day | N/A | | 83 |
| 84 | | | | | | | Minimum: Instrument-rated Meters | $ 1.134 | /day | $ 1.150 | /day | N/A | | 84 |
| 85 | | | | | | | Minimum: Primary Meters | $ 2.926 | /day | $ 2.968 | /day | N/A | | 85 |
| 86 | | | | | | | Minimum: Transmission Meters | $ 22.422 | /day | $ 22.745 | /day | N/A | | 86 |
| 87 | | | | Minimum - Demand Charge | 1.60 | /kW | Minimum - Demand Charge | 1.75 | /kW | 1.78 | /kW | 0.18 | /kW | 87 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

**ARIZONA PUBLIC SERVICE COMPANY**

**CHANGES IN REPRESENTATIVE RATE SCHEDULES**
**COMPARISON OF PRESENT AND PROPOSED RATES**

**TEST YEAR ENDING DECEMBER 31, 2002**

| Line No. | (A) Rate Schedule | (B) Description | (C) Season | (D) Present Rates Block | (E) Present Rates Rates | (F) | (G) Proposed Rates Block | (H) Proposed Rates Rates | (I) | (J) Proposed Rates with Franchise Fees (H) x 0.0144 | (K) | (L) Change (J) - (E) | (M) Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 88 | Experimental General Service | | Summer | | | | E-32TOU: 20 kW or less | | | | | | 88 |
| 89 | Time-of-Use Rate Schedules | | | | | | BSC: Self-Contained Meters | $ 0.600 | /day | $ 0.609 | /day | N/A | 89 |
| 90 | E-21, E-22, E-23, E-24 | | | | | | BSC: Instrument-rated Meters | 1.134 | /day | 1.150 | /day | N/A | 90 |
| 91 | are cancelled and are replaced by | | | | | | BSC: Primary Meters | 2.926 | /day | 2.968 | /day | N/A | 91 |
| 92 | General Service Time-of-Use | | | | | | All On-Peak kWh: Secondary | 0.11375 | /kWh | 0.11539 | /kWh | N/A | 92 |
| 93 | Rate Schedule E-32TOU | | | | | | All Off-Peak kWh: Secondary | 0.09375 | /kWh | 0.09510 | /kWh | N/A | 93 |
| 94 | | | | | | | All On-Peak kWh: Primary | 0.10653 | /kWh | 0.10806 | /kWh | | 94 |
| 95 | | | | | | | All Off-Peak kWh: Primary | 0.08653 | /kWh | 0.08778 | /kWh | | 95 |
| 96 | | | Winter | | | | BSC: Self-Contained Meters | $ 0.600 | /day | $ 0.609 | /day | N/A | 96 |
| 97 | | | | | | | BSC: Instrument-rated Meters | 1.134 | /day | 1.134 | /day | N/A | 97 |
| 98 | | | | | | | BSC: Primary Meters | 2.926 | /day | 2.926 | /day | N/A | 98 |
| 99 | | | | | | | All kWh: Secondary | 0.09095 | /kWh | 0.09226 | /kWh | N/A | 99 |
| 100 | | | | | | | All kWh: Primary | 0.08373 | /kWh | 0.08494 | /kWh | | 100 |
| 101 | | | Summer | | | | E-32TOU: Over 20 kW | | | | | | 101 |
| 102 | | | | | | | BSC: Self-Contained Meters | $ 0.600 | /day | $ 0.609 | /day | N/A | 102 |
| 103 | | | | | | | BSC: Instrument-rated Meters | 1.134 | /day | 1.134 | /day | N/A | 103 |
| 104 | | | | | | | BSC: Primary Meters | 2.926 | /day | 2.926 | /day | N/A | 104 |
| 105 | | | | | | | BSC: Transmission Meters | 22.422 | /day | 22.745 | /day | N/A | 105 |
| 106 | | | | | | | First 500 On-Peak kW: Secondary | 15.046 | /kW | 15.263 | /kW | N/A | 106 |
| 107 | | | | | | | All additional On-Peak kW: Secondary | 13.316 | /kW | 13.508 | /kW | N/A | 107 |
| 108 | | | | | | | Residual Off-Peak kW: Secondary | 6.783 | /kW | 6.881 | /kW | N/A | 108 |
| 109 | | | | | | | First 500 On-Peak kW: Primary | 13.456 | /kW | 13.650 | /kW | N/A | 109 |
| 110 | | | | | | | All additional On-Peak kW: Primary | 11.726 | /kW | 11.895 | /kW | N/A | 110 |
| 111 | | | | | | | Residual Off-Peak kW: Primary | 5.193 | /kW | 5.268 | /kW | N/A | 111 |
| 112 | | | | | | | First 500 On-Peak kW: Trans. | 10.446 | /kW | 10.596 | /kW | N/A | 112 |
| 113 | | | | | | | All additional On-Peak kW: Trans. | 8.716 | /kW | 8.842 | /kW | N/A | 113 |
| 114 | | | | | | | Residual Off-Peak kW: Trans. | 2.183 | /kW | 2.214 | /kW | N/A | 114 |
| 115 | | | | | | | All On-Peak kWh | 0.04855 | /kWh | 0.04925 | /kWh | N/A | 115 |
| 116 | | | | | | | All Off-Peak kWh | 0.03855 | /kWh | 0.03911 | /kWh | N/A | 116 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

## ARIZONA PUBLIC SERVICE COMPANY

## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND PROPOSED RATES

## TEST YEAR ENDING DECEMBER 31, 2002

| Line No. | (A) Rate Schedule | (B) Description | (C) Season | (D) Present Rates Block | (E) Present Rates Rates | (F) | (G) Proposed Rates Block | (H) Proposed Rates Rates | (I) | (J) Proposed Rates with Franchise Fees (H) x 0.0144 | (K) | (L) Change (J) - (E) | (M) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 117 | Experimental General Service | | Winter | | | | BSC: Self-Contained Meters | $ 0.600 | /day | $ 0.609 | /day | N/A | | 117 |
| 118 | Time-of-Use Rate Schedules | | | | | | BSC: Instrument-rated Meters | 1.134 | /day | 1.150 | /day | N/A | | 118 |
| 119 | E-21, E-22, E-23, E-24 | | | | | | BSC: Primary Meters | 2.926 | /day | 2.968 | /day | N/A | | 119 |
| 120 | are cancelled and are replaced by | | | | | | BSC: Transmission Meters | 22.422 | /day | 22.745 | /day | N/A | | 120 |
| 121 | General Service Time-of-Use | | | | | | First 500 On-Peak kW: Secondary | 15.046 | /kW | 15.263 | /kW | N/A | | 121 |
| 122 | Rate Schedule E-32TOU | | | | | | All additional On-Peak kW: Secondary | 13.316 | /kW | 13.508 | /kW | N/A | | 122 |
| 123 | (cont) | | | | | | Residual Off-Peak kW: Secondary | 6.783 | /kW | 6.881 | /kW | N/A | | 123 |
| 124 | | | | | | | First 500 On-Peak kW: Primary | 13.456 | /kW | 13.650 | /kW | N/A | | 124 |
| 125 | | | | | | | All additional On-Peak kW: Primary | 11.726 | /kW | 11.895 | /kW | N/A | | 125 |
| 126 | | | | | | | Residual Off-Peak kW: Primary | 5.193 | /kW | 5.268 | /kW | N/A | | 126 |
| 127 | | | | | | | First 500 On-Peak kW: Trans. | 10.446 | /kW | 10.596 | /kW | N/A | | 127 |
| 128 | | | | | | | All additional On-Peak kW: Trans. | 8.716 | /kW | 8.842 | /kW | N/A | | 128 |
| 129 | | | | | | | Residual Off-Peak kW: Trans. | 2.183 | /kW | 2.214 | /kW | N/A | | 129 |
| 130 | | | | | | | All kWh | 0.03290 | /kWh | 0.03337 | /kWh | N/A | | 130 |
| 131 | | | Sum & Win | | | | Minimum: Self-Contained Meters | $ 0.600 | /day | $ 0.609 | /day | N/A | | 131 |
| 132 | | | | | | | Minimum: Instrument-rated Meters | 1.134 | /day | 1.150 | /day | N/A | | 132 |
| 133 | | | | | | | Minimum: Primary Meters | 2.926 | /day | 2.968 | /day | N/A | | 133 |
| 134 | | | | | | | Minimum: Transmission Meters | 22.422 | /day | 22.745 | /day | N/A | | 134 |
| 135 | | | | | | | Minimum - Demand Charge | 1.75 | /kW | 1.78 | /kW | N/A | | 135 |
| 136 | E-30 | Extra Small General Service Unmetered | Summer | Basic Service Charge | $ 6.25 | /mo | | | | | | N/A | | 136 |
| 137 | | | | | | | Basic Service Charge | $ 0.286 | /day | $ 0.290 | /day | N/A | | 137 |
| 138 | | | | All kWh | 0.10179 | /kWh | All kWh | 0.10091 | /kWh | 0.10236 | /kWh | 0.00057 | /kWh | 138 |
| 139 | | | Winter | Basic Service Charge | $ 6.25 | /mo | | | | | | N/A | | 139 |
| 140 | | | | | | | Basic Service Charge | $ 0.286 | /day | $ 0.290 | /day | N/A | | 140 |
| 141 | | | | All kWh | 0.09168 | /kWh | All kWh | 0.09091 | /kWh | 0.09222 | /kWh | 0.00054 | /kWh | 141 |
| 142 | | | Sum & Win | Minimum | $ 6.25 | /mo | | | | | | N/A | | 142 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

# ARIZONA PUBLIC SERVICE COMPANY

## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND PROPOSED RATES

## TEST YEAR ENDING DECEMBER 31, 2002

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Present Rates | | | Proposed Rates | | | Proposed Rates with | | | |
| Line No. | Rate Schedule | Description | Season | Block | Rates | | Block | Rates | | Franchise Fees (H) x 0.0144 | | Change (J) - (E) | Line No. |
| 143 | | | | | | | E-32: 20 kW or less | | | | | | 143 |
| 144 | E-32 | General Service | Summer | Basic Service Charge | $ 12.50 | /mo | | | | | | N/A | 144 |
| 145 | | | | | | | BSC: Self-Contained Meters | $ 0.575 | /day | $ 0.583 | /day | N/A | 145 |
| 146 | | | | | | | BSC: Instrument-rated Meters | 1.134 | /day | 1.150 | /day | N/A | 146 |
| 147 | | | | | | | BSC: Primary Meters | 2.926 | /day | 2.968 | /day | N/A | 147 |
| 148 | | | | All kW over 5 | 1.70 | /kW | | | | | | N/A | 148 |
| 149 | | | | First 2,500 kWh: | 0.10201 | /kWh | | | | | | N/A | 149 |
| 150 | | | | Next 100 kWh per kW over 5: | 0.10201 | /kWh | | | | | | N/A | 150 |
| 151 | | | | Next 42,000 kWh | 0.06989 | /kWh | | | | | | N/A | 151 |
| 152 | | | | All additional kWh | 0.04403 | /kWh | | | | | | N/A | 152 |
| 153 | | | | | | | All kWh: Secondary | 0.10095 | /kWh | 0.10240 | /kWh | N/A | 153 |
| 154 | | | | | | | All kWh: Primary | 0.09373 | /kWh | 0.09508 | /kWh | N/A | 154 |
| 155 | | | Winter | Basic Service Charge | $ 12.50 | /mo | | | | | | N/A | 155 |
| 156 | | | | | | | BSC: Self-Contained Meters | $ 0.575 | /day | $ 0.583 | /day | N/A | 156 |
| 157 | | | | | | | BSC: Instrument-rated Meters | 1.134 | /day | 1.150 | /day | N/A | 157 |
| 158 | | | | | | | BSC: Primary Meters | 2.926 | /day | 2.968 | /day | N/A | 158 |
| 159 | | | | All kW over 5 | 1.55 | /kW | | | | | | N/A | 159 |
| 160 | | | | First 2,500 kWh: | 0.09188 | /kWh | | | | | | N/A | 160 |
| 161 | | | | Next 100 kWh per kW over 5: | 0.09188 | /kWh | | | | | | N/A | 161 |
| 162 | | | | Next 42,000 kWh | 0.06276 | /kWh | | | | | | N/A | 162 |
| 163 | | | | All additional kWh | 0.03937 | /kWh | | | | | | N/A | 163 |
| 164 | | | | | | | All kWh: Secondary | 0.09095 | /kWh | 0.09226 | /kWh | N/A | 164 |
| 165 | | | | | | | All kWh: Primary | 0.08373 | /kWh | 0.08494 | /kWh | N/A | 165 |
| 166 | | | Sum & Win | Minimum - Basic Service Charge | $ 12.50 | /mo | | | | | | N/A | 166 |
| 167 | | | | Minimum - Demand Charge | 1.60 | /kW | | | | | | N/A | 167 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

**ARIZONA PUBLIC SERVICE COMPANY**

**CHANGES IN REPRESENTATIVE RATE SCHEDULES**
**COMPARISON OF PRESENT AND PROPOSED RATES**

**TEST YEAR ENDING DECEMBER 31, 2002**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Present Rates | | | Proposed Rates | | | Proposed Rates with | | | |
| Line No. | Rate Schedule | Description | Season | Block | Rates | | Block | Rates | | Franchise Fees | | Change | Line No. |
| | | | | | | | | | | (H) x 0.0144 | | (J) - (E) | |
| 168 | | | | | | | E-32: Over 20 kW | | | | | | 168 |
| 169 | E-32 | General Service | Summer | Basic Service Charge | $ 12.50 | /mo | | | | | | N/A | 169 |
| 170 | (cont) | | | | | | BSC: Self-Contained Meters | $ 0.575 | /day | $ 0.583 | /day | N/A | 170 |
| 171 | | | | | | | BSC: Instrument-rated Meters | 1.134 | /day | 1.150 | /day | N/A | 171 |
| 172 | | | | | | | BSC: Primary Meters | 2.926 | /day | 2.968 | /day | N/A | 172 |
| 173 | | | | | | | BSC: Transmission Meters | 22.422 | /day | 22.745 | /day | N/A | 173 |
| 174 | | | | All kW over 5 | 1.70 | /kW | | | | | | N/A | 174 |
| 175 | | | | | | | First 500 kW: Secondary | 6.348 | /kW | 6.439 | /kW | N/A | 175 |
| 176 | | | | | | | All additional kW: Secondary | 4.618 | /kW | 4.684 | /kW | N/A | 176 |
| 177 | | | | | | | First 500 kW: Primary | 4.758 | /kW | 4.827 | /kW | N/A | 177 |
| 178 | | | | | | | All additional kW: Primary | 3.028 | /kW | 3.072 | /kW | N/A | 178 |
| 179 | | | | | | | First 500 kW: Trans. | 1.748 | /kW | 1.773 | /kW | N/A | 179 |
| 180 | | | | | | | All additional kW: Trans. | 0.018 | /kW | 0.018 | /kW | N/A | 180 |
| 181 | | | | First 2,500 kWh: | 0.10201 | /kWh | | | | | | N/A | 181 |
| 182 | | | | Next 100 kWh per kW over 5: | 0.10201 | /kWh | | | | | | N/A | 182 |
| 183 | | | | Next 42,000 kWh | 0.06989 | /kWh | | | | | | N/A | 183 |
| 184 | | | | All additional kWh | 0.04403 | /kWh | | | | | | N/A | 184 |
| 185 | | | | | | | First 200 kWh per kW: | 0.08518 | /kWh | 0.08641 | /kWh | N/A | 185 |
| 186 | | | | | | | All additional kWh: | 0.04290 | /kWh | 0.04352 | /kWh | N/A | 186 |
| 187 | | | Winter | Basic Service Charge | $ 12.50 | /mo | | | | | | N/A | 187 |
| 188 | | | | | | | BSC: Self-Contained Meters | $ 0.575 | /day | $ 0.583 | /day | N/A | 188 |
| 189 | | | | | | | BSC: Instrument-rated Meters | 1.134 | /day | 1.150 | /day | N/A | 189 |
| 190 | | | | | | | BSC: Primary Meters | 2.926 | /day | 2.968 | /day | N/A | 190 |
| 191 | | | | | | | BSC: Transmission Meters | 22.422 | /day | 22.745 | /day | N/A | 191 |
| 192 | | | | All kW over 5 | 1.55 | /kW | | | | | | N/A | 192 |
| 193 | | | | | | | First 500 kW: Secondary | 6.348 | /kW | 6.439 | /kW | N/A | 193 |
| 194 | | | | | | | All additional kW: Secondary | 4.618 | /kW | 4.684 | /kW | N/A | 194 |
| 195 | | | | | | | First 500 kW: Primary | 4.758 | /kW | 4.827 | /kW | N/A | 195 |
| 196 | | | | | | | All additional kW: Primary | 3.028 | /kW | 3.072 | /kW | N/A | 196 |
| 197 | | | | | | | First 500 kW: Trans. | 1.748 | /kW | 1.773 | /kW | N/A | 197 |
| 198 | | | | | | | All additional kW: Trans. | 0.018 | /kW | 0.018 | /kW | N/A | 198 |
| 199 | | | | First 2,500 kWh: | 0.09188 | /kWh | | | | | | N/A | 199 |
| 200 | | | | Next 100 kWh per kW over 5: | 0.09188 | /kWh | | | | | | N/A | 200 |
| 201 | | | | Next 42,000 kWh | 0.06276 | /kWh | | | | | | N/A | 201 |
| 202 | | | | All additional kWh | 0.03937 | /kWh | | | | | | N/A | 202 |
| 203 | | | | | | | First 200 kWh per kW: | 0.07518 | /kWh | 0.07626 | /kWh | N/A | 203 |
| 204 | | | | | | | All additional kWh: | 0.03290 | /kWh | 0.03337 | /kWh | N/A | 204 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

## ARIZONA PUBLIC SERVICE COMPANY

## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND PROPOSED RATES

## TEST YEAR ENDING DECEMBER 31, 2002

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Present Rates | | | Proposed Rates | | | Proposed Rates with | | | | |
| Line No. | Rate Schedule | Description | Season | Block | Rates | | Block | Rates | | Franchise Fees (H) x 0.0144 | | Change (J) - (E) | | Line No. |
| 205 | E-32 | | Sum & Win | Minimum - Basic Service Charge | $ 12.50 | /mo | | | | | | N/A | | 205 |
| 206 | (cont) | | | | | | Minimum: Self-Contained Meters | $ 0.575 | /day | $ 0.583 | /day | N/A | | 206 |
| 207 | | | | | | | Minimum: Instrument-rated Meters | 1.134 | /day | 1.150 | /day | N/A | | 207 |
| 208 | | | | | | | Minimum: Primary Meters | 2.926 | /day | 2.968 | /day | N/A | | 208 |
| 209 | | | | | | | Minimum: Transmission Meters | 22.422 | /day | 22.745 | /day | N/A | | 209 |
| 210 | | | | Minimum - Demand Charge | 1.60 | /kW | Minimum - Demand Charge | 1.75 | /kW | 1.78 | /kW | 0.18 | /mo | 210 |
| 211 | E-32R | Partial Requirements | | NO CHANGE | | | NO CHANGE | | | | | | | 211 |
| 212 | | General Service | | | | | | | | | | | | 212 |
| 213 | E-34 | Extra Large General | Sum & Win | Basic Service Charge | $ 2,430.00 | /mo | | | | | | N/A | | 213 |
| 214 | | Service | | | | | BSC: Self-Contained Meters | $ 0.575 | /day | $ 0.583 | /day | N/A | | 214 |
| 215 | | | | | | | BSC: Instrument-rated Meters | 1.134 | /day | 1.150 | /day | N/A | | 215 |
| 216 | | | | | | | BSC: Primary Meters | 2.926 | /day | 2.968 | /day | N/A | | 216 |
| 217 | | | | | | | BSC: Transmission Meters | 22.422 | /day | 22.745 | /day | N/A | | 217 |
| 218 | | | | All kW | 10.61 | /kW | All kW: Secondary | 13.062 | /kW | 13.250 | /kW | 2.640 | /kW | 218 |
| 219 | | | | | | | All kW: Primary | 12.372 | /kW | 12.550 | /kW | N/A | | 219 |
| 220 | | | | | | | All kW: Trans. | 8.882 | /kW | 9.010 | /kW | N/A | | 220 |
| 221 | | | | All kWh | 0.03126 | /kWh | All kWh | 0.03284 | /kWh | 0.03331 | /kWh | 0.00205 | /kWh | 221 |
| 222 | | | Sum & Win | Minimum - Basic Service Charge | $ 2,430.00 | /mo | | | | | | N/A | | 222 |
| 223 | | | | Minimum - Demand Charge | 10.61 | /kW | | | | | | N/A | | 223 |
| 224 | E-35 | Extra Large General | Sum & Win | Basic Service Charge | $ 2,450.00 | /mo | | | | | | N/A | | 224 |
| 225 | | Service Time of Use | | | | | BSC: Self-Contained Meters | $ 0.600 | /day | $ 0.609 | /day | N/A | | 225 |
| 226 | | | | | | | BSC: Instrument-rated Meters | 1.134 | /day | 1.150 | /day | N/A | | 226 |
| 227 | | | | | | | BSC: Primary Meters | 2.926 | /day | 2.968 | /day | N/A | | 227 |
| 228 | | | | | | | BSC: Transmission Meters | 22.422 | /day | 22.745 | /day | N/A | | 228 |
| 229 | | | | All On-Peak kW | 13.05 | /kW | All On-Peak kW: Secondary | 13.598 | /kW | 13.794 | /kW | 0.744 | /kW | 229 |
| 230 | | | | Excess Off-Peak Billing Demand | 6.53 | /kW | Excess Off-Peak kW: Secondary | 6.717 | /kW | 6.814 | /kW | 0.284 | /kW | 230 |
| 231 | | | | | | | All On-Peak kW: Primary | 12.908 | /kW | 13.094 | /kW | N/A | | 231 |
| 232 | | | | | | | Excess Off-Peak kW: Primary | 6.027 | /kW | 6.114 | /kW | N/A | | 232 |
| 233 | | | | | | | All On-Peak kW: Trans. | 9.418 | /kW | 9.554 | /kW | N/A | | 233 |
| 234 | | | | | | | Excess Off-Peak kW: Trans. | 2.537 | /kW | 2.574 | /kW | N/A | | 234 |
| 235 | | | | All On-Peak kWh | 0.03605 | /kWh | All On-Peak kWh | 0.03618 | /kWh | 0.03670 | /kWh | 0.00065 | /kWh | 235 |
| 236 | | | | All Off-Peak kWh | 0.02105 | /kWh | All Off-Peak kWh | 0.02868 | /kWh | 0.02909 | /kWh | 0.00804 | /kWh | 236 |
| 237 | | | Sum & Win | Minimum - Basic Service Charge | $ 2,450.00 | /mo | | | | | | N/A | | 237 |
| 238 | | | | Minimum - Demand Charge | 13.05 | /kW | | | | | | N/A | | 238 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

**ARIZONA PUBLIC SERVICE COMPANY**

**CHANGES IN REPRESENTATIVE RATE SCHEDULES**
**COMPARISON OF PRESENT AND PROPOSED RATES**

**TEST YEAR ENDING DECEMBER 31, 2002**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Present Rates | | | Proposed Rates | | | Proposed Rates with Franchise Fees | | Change | | |
| Line No. | Rate Schedule | Description | Season | Block | Rates | | Block | Rates | | (H) x 0.0144 | | (J) - (E) | | Line No. |
| 239 | E-36 | Station Use Service | | NO CHANGE | | | NO CHANGE | | | | | | | 239 |
| 240 | E-38 | Agricultural | | Rate Schedules E-38 and E-38-8T | | | | | | | | | | 240 |
| 241 | | Irrigation Service | | are being cancelled. Customers will be moved to | | | | | | | | | | 241 |
| 242 | | | | E-221 and E-221-8T. | | | | | | | | | | 242 |
| 243 | E-40 | Agricultural Wind | Sum & Win | Service Charge $/HP/yr | $ 12.23 | /mo | Service Charge $/HP/yr | $ 13.37 | /mo | $ 13.56 | /mo | $ 1.33 | /mo | 243 |
| 244 | | Machine Service | | All kWh | 0.06256 | /kWh | All kWh | 0.06838 | /kWh | 0.06936 | /kWh | 0.00680 | /kWh | 244 |
| 245 | E-47 | Dusk to Dawn Lighting | | Rate Schedule E-47 is completely redesigned; therefore | | | | | | | | | | 245 |
| 246 | | Service | | one-on-one comparisons are not meaningful. Please see | | | | | | | | | | 246 |
| 247 | | | | the actual rate schedule itself for rates. | | | | | | | | | | 247 |
| 248 | E-51 | Optional Electric | Sum & Win | Basic Service Charge | $ 8.00 | /mo | | | | | | N/A | | 248 |
| 249 | | Service for Qualified | | Generator Meter Charge | 24.00 | /mo | | | | | | N/A | | 249 |
| 250 | | Cogeneration and Small | | | | | Basic Service Charge | $ 0.263 | /day | $ 0.267 | /day | N/A | | 250 |
| 251 | | Power Production | | | | | Generator Meter Charge | $ 0.789 | /day | $ 0.800 | /day | N/A | | 251 |
| 252 | | | Sum & Win | Reservation Charge per kW | $ 1.99 | /kW | Reservation Charge per kW | $ 1.98 | /kW | 2.01 | /kW | 0.020 | /kW | 252 |
| 253 | | Facilities over 100 KW | | Initial Reservation Charge | 19.79 | /kW | Initial Reservation Charge | 19.79 | /kW | 20.07 | /kW | 0.280 | /kW | 253 |
| 254 | | | Summer | Standby - All On-Peak kWh | 0.04383 | /kWh | Standby - All On-Peak kWh | 0.04383 | /kWh | 0.04446 | /kWh | 0.00063 | /kWh | 254 |
| 255 | | | | Standby - All Off-Peak kWh | 0.02040 | /kWh | Standby - All Off-Peak kWh | 0.02040 | /kWh | 0.02069 | /kWh | 0.00029 | /kWh | 255 |
| 256 | | | Winter | Standby - All On-Peak kWh | 0.03115 | /kWh | | | | | | N/A | | 256 |
| 257 | | | | Standby - All Off-Peak kWh | 0.02040 | /kWh | | | | | | N/A | | 257 |
| 258 | | | | | | | Standby - All kWh | 0.02234 | /kWh | 0.02266 | /kWh | N/A | | 258 |
| 259 | | | Sum & Win | Maintenance - All kWh | $ 0.02040 | /kWh | Maintenance - All kWh | $ 0.02040 | /kWh | 0.02069 | /kWh | 0.00029 | /kWh | 259 |
| 260 | E-52 | Electric Service for | | NO CHANGE | | | NO CHANGE | | | | | | | 260 |
| 261 | | Partial Requirements | | | | | | | | | | | | 261 |
| 262 | | Service of less than | | | | | | | | | | | | 262 |
| 263 | | 3000 kW | | | | | | | | | | | | 263 |
| 264 | E-53 | Electric Service for | | NO CHANGE | | | NO CHANGE | | | | | | | 264 |
| 265 | | Athletic Stadiums | | | | | | | | | | | | 265 |
| 266 | | and Sports Fields | | | | | | | | | | | | 266 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

## ARIZONA PUBLIC SERVICE COMPANY

## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND PROPOSED RATES

## TEST YEAR ENDING DECEMBER 31, 2002

| Line No. | (A) Rate Schedule | (B) Description | (C) Season | (D) Present Rates Block | (E) Present Rates Rates | (F) | (G) Proposed Rates Block | (H) Proposed Rates Rates | (I) | (J) Proposed Rates with Franchise Fees (H) x 0.0144 | (K) | (L) Change (J) - (E) | (M) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 267 | E-54 | Seasonal Service | | NO CHANGE | | | NO CHANGE | | | | | | | 267 |
| 268<br>269<br>270<br>271 | E-55 | Electric Service for Partial Requirements Service of 3000 kW or greater | | NO CHANGE | | | NO CHANGE | | | | | | | 268<br>269<br>270<br>271 |
| 272<br>273<br>274 | E-58 | Street Lighting Service | | Rate Schedule E-58 is completely redesigned; therefore one-on-one comparisons are not meaningful. Please see the actual rate schedule itself for rates. | | | | | | | | | | 272<br>273<br>274 |
| 275 | E-59 | Energy Services for Govt Owned ST. Lighting Systems | Sum & Win | Service Charge | $ 1.79 | /mo | Service Charge | $ 2.45 | /mo | $ 2.49 | /mo | $ 0.70 | /mo | 275 |
| 276 | | | | Energy Charge | 0.05870 | /kWh | Energy Charge | 0.04635 | /kWh | 0.04702 | /kWh | (0.01168) | /kWh | 276 |
| 277 | E-66 | Share the Light | | NO CHANGE | | | NO CHANGE | | | | | | | 277 |
| 278<br>279 | E-67 | Municipal Lighting Service -- City of Phoenix | Sum & Win | All kWh | $ 0.03480 | /kWh | All kWh | $ 0.04128 | /kWh | 0.04187 | /kWh | $ 0.00707 | /kWh | 278<br>279 |
| 280 | E-114 | Share the Light | | NO CHANGE | | | NO CHANGE | | | | | | | 280 |
| 281 | E-116 | Share the Light | | NO CHANGE | | | NO CHANGE | | | | | | | 281 |
| 282 | E-145 | Share the Light | | NO CHANGE | | | NO CHANGE | | | | | | | 282 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

**ARIZONA PUBLIC SERVICE COMPANY**

**CHANGES IN REPRESENTATIVE RATE SCHEDULES**
**COMPARISON OF PRESENT AND PROPOSED RATES**

**TEST YEAR ENDING DECEMBER 31, 2002**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Present Rates | | | Proposed Rates | | | Proposed Rates with | | | | |
| Line No. | Rate Schedule | Description | Season | Block | Rates | | Block | Rates | | Franchise Fees (H) x 0.0144 | | Change (J) - (E) | | Line No. |
| 283 | E-221 | Water Pumping Service | Sum & Win | Basic Service Charge | $ 15.00 | /mo | | | | | | N/A | | 283 |
| 284 | | | | | | | Basic Service Charge | $ 0.575 | /day | $ 0.583 | /day | N/A | | 284 |
| 285 | | | | All kW | 1.62 | /kW | All kW | 1.80 | /kW | 1.83 | /kW | 0.21 | /kW | 285 |
| 286 | | | | First 240 kWh | 0.09475 | /kWh | | | | | | N/A | | 286 |
| 287 | | | | Next 275 kWh per kW | 0.06441 | /kWh | First 275 kWh per kW | 0.06911 | /kWh | 0.07011 | /kWh | 0.00570 | /kWh | 287 |
| 288 | | | | All additional kWh | 0.05289 | /kWh | All additional kWh | 0.05562 | /kWh | 0.05642 | /kWh | 0.00353 | /kWh | 288 |
| 289 | | | Sum & Win | Based on Measured kWh in Control Period: | | | Based on Measured kWh in Control Period: | | | | | | | 289 |
| 290 | | | | 2 kWh per kW or less | $ (0.00690) | /kWh | 2 kWh per kW or less | $(0.00739) | /kWh | (0.00750) | /kWh | $ (0.00060) | /kWh | 290 |
| 291 | | | | Greater than 8 kWh/kW | 0.00345 | /kWh | Greater than 8 kWh/kW | 0.00370 | /kWh | 0.00375 | /kWh | 0.00030 | /kWh | 291 |
| 292 | | | Sum & Win | Minimum Basic Service Charge | $ 15.00 | /mo | | | | | | N/A | | 292 |
| 293 | | | | | | | Minimum Basic Service Charge | $ 0.575 | /day | $ 0.583 | /day | N/A | | 293 |
| 294 | | | | Minimum Demand Charge | 1.62 | /kW | Minimum Demand Charge | 1.80 | /kW | 1.83 | /kW | 0.21 | /kW | 294 |
| 295 | | | | Minimum Annual kW Charge | 19.66 | /kW | Minimum Annual kW Charge | 21.60 | /kW | 21.91 | /kW | 2.25 | /kW | 295 |
| 296 | E-221-8T | Water Pumping Service Time Of Use | Sum & Win | Basic Service Charge | $ 25.87 | /mo | | | | | | N/A | | 296 |
| 297 | | | | | | | Basic Service Charge | $ 0.851 | /day | $ 0.863 | /day | N/A | | 297 |
| 298 | | | | All On-Peak kW | 3.85 | /kW | All On-Peak kW | 4.21 | /kW | 4.27 | /kW | 0.42 | /kW | 298 |
| 299 | | | | All Off-Peak kW | 2.30 | /kW | All Off-Peak kW | 2.51 | /kW | 2.55 | /kW | 0.25 | /kW | 299 |
| 300 | | | | All On-Peak kWh | 0.07769 | /kWh | All On-Peak kWh | 0.08492 | /kWh | 0.08614 | /kWh | 0.00845 | /kWh | 300 |
| 301 | | | | All Off-Peak kWh | 0.04178 | /kWh | All Off-Peak kWh | 0.04567 | /kWh | 0.04633 | /kWh | 0.00455 | /kWh | 301 |
| 302 | | | Sum & Win | Minimum Basic Service Charge | $ 25.87 | /mo | | | | | | N/A | | 302 |
| 303 | | | | | | | Minimum Basic Service Charge | $ 0.851 | /day | $ 0.863 | /day | N/A | | 303 |
| 304 | | | | Minimum Demand Charge | 2.30 | /kW | Minimum Demand Charge | 2.51 | /kW | 2.55 | /kW | 0.25 | /kW | 304 |
| 305 | | | | Minimum Annual kW Charge | 27.79 | /kW | Minimum Annual kW Charge | 30.12 | /kW | 30.55 | /kW | 2.76 | /kW | 305 |
| 306 | E-249 | Share the Light | | NO CHANGE | | | NO CHANGE | | | | | | | 306 |
| 307 | EPR-2 | Purchase Rates | | NO CHANGE | | | NO CHANGE | | | | | | | 307 |
| 308 | EPR-3 | Purchase Rates | | NO CHANGE | | | NO CHANGE | | | | | | | 308 |
| 309 | EPR-4 | Purchase Rates | | NO CHANGE | | | NO CHANGE | | | | | | | 309 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

## ARIZONA PUBLIC SERVICE COMPANY

## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND PROPOSED RATES

## TEST YEAR ENDING DECEMBER 31, 2002

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Present Rates | | | Proposed Rates | | | Proposed Rates with | | | |
| Line No. | Rate Schedule | Description | Season | Block | Rates | Block | Rates | | Franchise Fees (H) x 0.0144 | | Change (J) - (E) | Line No. |
| 310 | EQF-M | Scheduled Maintenance Electric Service | | NO CHANGE | | NO CHANGE | | | | | | 310 |
| 311 | | for Qualified CoGenerators and | | | | | | | | | | 311 |
| 312 | | Small Power Production Facilities | | | | | | | | | | 312 |
| 313 | EQF-S | Standby Electric Service for Qualified | | NO CHANGE | | NO CHANGE | | | | | | 313 |
| 314 | | CoGenerators and Small Power | | | | | | | | | | 314 |
| 315 | | Production Facilities | | | | | | | | | | 315 |
| 316 | Solar-1 | Photovoltaic Service | | NO CHANGE | | NO CHANGE | | | | | | 316 |
| 317 | | Pilot Program | | | | | | | | | | 317 |
| 318 | Solar-2 | Individual Solar | | NO CHANGE | | NO CHANGE | | | | | | 318 |
| 319 | | Electric Service | | | | | | | | | | 319 |
| 320 | SP-1 | Solar Partners | | NO CHANGE | | NO CHANGE | | | | | | 320 |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

H-4

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**E-10 Winter (November-April)**

**Customer Bills at Varying Consumption Levels**
**at Present and STEP 1 Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|
| | | Components of Proposed Bill - Step 1 | | | | Change | |
| Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | (A) x $0.000353 | [(C) + (D)] x 0.0144 | (C) + (D) + (E) | (F) - (B) | (G) / (B) |
| 200 | 22.72 | 24.83 | 0.07 | 0.36 | 25.26 | 2.54 | 11.2% |
| 250 | 26.52 | 29.00 | 0.09 | 0.42 | 29.51 | 2.99 | 11.3% |
| 300 | 30.33 | 33.18 | 0.11 | 0.48 | 33.77 | 3.44 | 11.3% |
| 350 | 34.13 | 37.35 | 0.12 | 0.54 | 38.01 | 3.88 | 11.4% |
| 400 | 37.94 | 41.53 | 0.14 | 0.60 | 42.27 | 4.33 | 11.4% |
| 450 | 41.74 | 45.70 | 0.16 | 0.66 | 46.52 | 4.78 | 11.5% |
| 500 | 45.55 | 49.88 | 0.18 | 0.72 | 50.78 | 5.23 | 11.5% |
| 550 | 49.35 | 54.05 | 0.19 | 0.78 | 55.02 | 5.67 | 11.5% |
| 600 | 53.15 | 58.22 | 0.21 | 0.84 | 59.27 | 6.12 | 11.5% |
| 650 | 56.96 | 62.40 | 0.23 | 0.90 | 63.53 | 6.57 | 11.5% |
| 700 | 60.76 | 66.57 | 0.25 | 0.96 | 67.78 | 7.02 | 11.6% |
| 750 | 64.57 | 70.75 | 0.26 | 1.02 | 72.03 | 7.46 | 11.6% |
| 800 | 68.37 | 74.92 | 0.28 | 1.08 | 76.28 | 7.91 | 11.6% |
| 850 | 72.18 | 79.10 | 0.30 | 1.14 | 80.54 | 8.36 | 11.6% |
| 900 | 75.98 | 83.27 | 0.32 | 1.20 | 84.79 | 8.81 | 11.6% |
| 950 | 79.79 | 87.45 | 0.34 | 1.26 | 89.05 | 9.26 | 11.6% |
| 1,000 | 83.59 | 91.62 | 0.35 | 1.32 | 93.29 | 9.70 | 11.6% |
| 1,100 | 91.20 | 99.97 | 0.39 | 1.45 | 101.81 | 10.61 | 11.6% |
| 1,200 | 98.81 | 108.32 | 0.42 | 1.57 | 110.31 | 11.50 | 11.6% |
| 1,300 | 106.42 | 116.67 | 0.46 | 1.69 | 118.82 | 12.40 | 11.7% |
| 1,400 | 114.03 | 125.02 | 0.49 | 1.81 | 127.32 | 13.29 | 11.7% |
| 1,500 | 121.64 | 133.37 | 0.53 | 1.93 | 135.83 | 14.19 | 11.7% |
| 1,600 | 129.24 | 141.71 | 0.56 | 2.05 | 144.32 | 15.08 | 11.7% |
| 1,700 | 136.85 | 150.06 | 0.60 | 2.17 | 152.83 | 15.98 | 11.7% |
| 1,800 | 144.46 | 158.41 | 0.64 | 2.29 | 161.34 | 16.88 | 11.7% |
| 1,900 | 152.07 | 166.76 | 0.67 | 2.41 | 169.84 | 17.77 | 11.7% |
| 2,000 | 159.68 | 175.11 | 0.71 | 2.53 | 178.35 | 18.67 | 11.7% |
| 2,200 | 174.90 | 191.81 | 0.78 | 2.77 | 195.36 | 20.46 | 11.7% |
| 2,400 | 190.12 | 208.51 | 0.85 | 3.01 | 212.37 | 22.25 | 11.7% |
| 2,600 | 205.33 | 225.20 | 0.92 | 3.26 | 229.38 | 24.05 | 11.7% |
| 2,800 | 220.55 | 241.90 | 0.99 | 3.50 | 246.39 | 25.84 | 11.7% |
| 3,000 | 235.77 | 258.60 | 1.06 | 3.74 | 263.40 | 27.63 | 11.7% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**E-10 Summer (May - October)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed STEP 1 Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|
| | | Components of Proposed Bill - Step 1 | | | | Change | |
| Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | (A) x $0.000353 | [(C) + (D)] x 0.0144 | (C) + (D) + (E) | (F) - (B) | (G) / (B) |
| 200 | 20.86 | 22.79 | 0.07 | 0.33 | 23.19 | 2.33 | 11.2% |
| 250 | 24.21 | 26.46 | 0.09 | 0.38 | 26.93 | 2.72 | 11.2% |
| 300 | 27.55 | 30.13 | 0.11 | 0.44 | 30.68 | 3.13 | 11.4% |
| 350 | 30.89 | 33.79 | 0.12 | 0.49 | 34.40 | 3.51 | 11.4% |
| 400 | 34.23 | 37.46 | 0.14 | 0.54 | 38.14 | 3.91 | 11.4% |
| 450 | 38.82 | 42.50 | 0.16 | 0.61 | 43.27 | 4.45 | 11.5% |
| 500 | 43.42 | 47.54 | 0.18 | 0.69 | 48.41 | 4.99 | 11.5% |
| 550 | 48.01 | 52.58 | 0.19 | 0.76 | 53.53 | 5.52 | 11.5% |
| 600 | 52.61 | 57.62 | 0.21 | 0.83 | 58.66 | 6.05 | 11.5% |
| 650 | 57.20 | 62.67 | 0.23 | 0.91 | 63.81 | 6.61 | 11.6% |
| 700 | 61.80 | 67.71 | 0.25 | 0.98 | 68.94 | 7.14 | 11.6% |
| 750 | 66.39 | 72.75 | 0.26 | 1.05 | 74.06 | 7.67 | 11.6% |
| 800 | 70.98 | 77.79 | 0.28 | 1.12 | 79.19 | 8.21 | 11.6% |
| 850 | 75.70 | 82.97 | 0.30 | 1.20 | 84.47 | 8.77 | 11.6% |
| 900 | 80.42 | 88.15 | 0.32 | 1.27 | 89.74 | 9.32 | 11.6% |
| 950 | 85.14 | 93.33 | 0.34 | 1.35 | 95.02 | 9.88 | 11.6% |
| 1,000 | 89.86 | 98.51 | 0.35 | 1.42 | 100.28 | 10.42 | 11.6% |
| 1,100 | 99.30 | 108.86 | 0.39 | 1.57 | 110.82 | 11.52 | 11.6% |
| 1,200 | 108.74 | 119.22 | 0.42 | 1.72 | 121.36 | 12.62 | 11.6% |
| 1,300 | 118.18 | 129.58 | 0.46 | 1.87 | 131.91 | 13.73 | 11.6% |
| 1,400 | 127.62 | 139.94 | 0.49 | 2.02 | 142.45 | 14.83 | 11.6% |
| 1,500 | 137.06 | 150.30 | 0.53 | 2.17 | 153.00 | 15.94 | 11.6% |
| 1,600 | 146.50 | 160.65 | 0.56 | 2.32 | 163.53 | 17.03 | 11.6% |
| 1,700 | 155.94 | 171.01 | 0.60 | 2.47 | 174.08 | 18.14 | 11.6% |
| 1,800 | 165.38 | 181.37 | 0.64 | 2.62 | 184.63 | 19.25 | 11.6% |
| 1,900 | 174.82 | 191.73 | 0.67 | 2.77 | 195.17 | 20.35 | 11.6% |
| 2,000 | 184.26 | 202.09 | 0.71 | 2.92 | 205.72 | 21.46 | 11.6% |
| 2,200 | 203.14 | 222.80 | 0.78 | 3.22 | 226.80 | 23.66 | 11.6% |
| 2,400 | 222.02 | 243.52 | 0.85 | 3.52 | 247.89 | 25.87 | 11.7% |
| 2,600 | 240.90 | 264.23 | 0.92 | 3.82 | 268.97 | 28.07 | 11.7% |
| 2,800 | 259.78 | 284.95 | 0.99 | 4.12 | 290.06 | 30.28 | 11.7% |
| 3,000 | 278.66 | 305.67 | 1.06 | 4.42 | 311.15 | 32.49 | 11.7% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**E-10 Winter (November-April)**

**Customer Bills at Varying Consumption Levels**
**at Proposed STEP 1 and Proposed E-12 Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|
| | | Components of Proposed Bill - E-12 | | | | Change | |
| Monthly kWh | Monthly Bill under Proposed Step 1 Rates | Base | CRCC | Franchise | Monthly Bill under Proposed E-12 | Amount ($) | % |
| | | | (A) x $0.000353 | [(C) + (D)] x 0.0144 | (C) + (D) + (E) | (F) - (B) | (G) / (B) |
| 200 | 24.83 | 26.34 | 0.07 | 0.38 | 26.79 | 1.96 | 7.9% |
| 250 | 29.00 | 29.84 | 0.09 | 0.43 | 30.36 | 1.36 | 4.7% |
| 300 | 33.18 | 33.34 | 0.11 | 0.48 | 33.93 | 0.75 | 2.3% |
| 350 | 37.35 | 36.84 | 0.12 | 0.53 | 37.49 | 0.14 | 0.4% |
| 400 | 41.53 | 40.35 | 0.14 | 0.58 | 41.07 | (0.46) | -1.1% |
| 450 | 45.70 | 43.85 | 0.16 | 0.63 | 44.64 | (1.06) | -2.3% |
| 500 | 49.88 | 47.35 | 0.18 | 0.68 | 48.21 | (1.67) | -3.3% |
| 550 | 54.05 | 50.85 | 0.19 | 0.73 | 51.77 | (2.28) | -4.2% |
| 600 | 58.22 | 54.35 | 0.21 | 0.79 | 55.35 | (2.87) | -4.9% |
| 650 | 62.40 | 57.86 | 0.23 | 0.84 | 58.93 | (3.47) | -5.6% |
| 700 | 66.57 | 61.36 | 0.25 | 0.89 | 62.50 | (4.07) | -6.1% |
| 750 | 70.75 | 64.86 | 0.26 | 0.94 | 66.06 | (4.69) | -6.6% |
| 800 | 74.92 | 68.36 | 0.28 | 0.99 | 69.63 | (5.29) | -7.1% |
| 850 | 79.10 | 71.86 | 0.30 | 1.04 | 73.20 | (5.90) | -7.5% |
| 900 | 83.27 | 75.37 | 0.32 | 1.09 | 76.78 | (6.49) | -7.8% |
| 950 | 87.45 | 78.87 | 0.34 | 1.14 | 80.35 | (7.10) | -8.1% |
| 1,000 | 91.62 | 82.37 | 0.35 | 1.19 | 83.91 | (7.71) | -8.4% |
| 1,100 | 99.97 | 89.37 | 0.39 | 1.29 | 91.05 | (8.92) | -8.9% |
| 1,200 | 108.32 | 96.38 | 0.42 | 1.39 | 98.19 | (10.13) | -9.4% |
| 1,300 | 116.67 | 103.38 | 0.46 | 1.50 | 105.34 | (11.33) | -9.7% |
| 1,400 | 125.02 | 110.39 | 0.49 | 1.60 | 112.48 | (12.54) | -10.0% |
| 1,500 | 133.37 | 117.39 | 0.53 | 1.70 | 119.62 | (13.75) | -10.3% |
| 1,600 | 141.71 | 124.39 | 0.56 | 1.80 | 126.75 | (14.96) | -10.6% |
| 1,700 | 150.06 | 131.40 | 0.60 | 1.90 | 133.90 | (16.16) | -10.8% |
| 1,800 | 158.41 | 138.40 | 0.64 | 2.00 | 141.04 | (17.37) | -11.0% |
| 1,900 | 166.76 | 145.41 | 0.67 | 2.10 | 148.18 | (18.58) | -11.1% |
| 2,000 | 175.11 | 152.41 | 0.71 | 2.20 | 155.32 | (19.79) | -11.3% |
| 2,200 | 191.81 | 166.42 | 0.78 | 2.41 | 169.61 | (22.20) | -11.6% |
| 2,400 | 208.51 | 180.43 | 0.85 | 2.61 | 183.89 | (24.62) | -11.8% |
| 2,600 | 225.20 | 194.43 | 0.92 | 2.81 | 198.16 | (27.04) | -12.0% |
| 2,800 | 241.90 | 208.44 | 0.99 | 3.02 | 212.45 | (29.45) | -12.2% |
| 3,000 | 258.60 | 222.45 | 1.06 | 3.22 | 226.73 | (31.87) | -12.3% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**E-10 Summer (May - October)**

**Customer Bills at Varying Consumption Levels**
**at Proposed STEP 1 and Proposed E-12 Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|
| | | Components of Proposed Bill - E-12 | | | | Change | |
| Monthly kWh | Monthly Bill under Proposed Step 1 Rates | Base | CRCC | Franchise | Monthly Bill under Proposed E-12 | Amount ($) | % |
| | | | (A) x $0.000353 | [(C) + (D)] x 0.0144 | (C) + (D) + (E) | (F) - (B) | (G) / (B) |
| 200 | 22.79 | 29.61 | 0.07 | 0.43 | 30.11 | 7.32 | 32.1% |
| 250 | 26.46 | 33.93 | 0.09 | 0.49 | 34.51 | 8.05 | 30.4% |
| 300 | 30.13 | 38.25 | 0.11 | 0.55 | 38.91 | 8.78 | 29.1% |
| 350 | 33.79 | 42.57 | 0.12 | 0.61 | 43.30 | 9.51 | 28.1% |
| 400 | 37.46 | 46.89 | 0.14 | 0.68 | 47.71 | 10.25 | 27.4% |
| 450 | 42.50 | 51.21 | 0.16 | 0.74 | 52.11 | 9.61 | 22.6% |
| 500 | 47.54 | 55.53 | 0.18 | 0.80 | 56.51 | 8.97 | 18.9% |
| 550 | 52.58 | 59.85 | 0.19 | 0.86 | 60.90 | 8.32 | 15.8% |
| 600 | 57.62 | 64.17 | 0.21 | 0.93 | 65.31 | 7.69 | 13.3% |
| 650 | 62.67 | 68.49 | 0.23 | 0.99 | 69.71 | 7.04 | 11.2% |
| 700 | 67.71 | 72.81 | 0.25 | 1.05 | 74.11 | 6.40 | 9.5% |
| 750 | 72.75 | 77.13 | 0.26 | 1.11 | 78.50 | 5.75 | 7.9% |
| 800 | 77.79 | 81.45 | 0.28 | 1.18 | 82.91 | 5.12 | 6.6% |
| 850 | 82.97 | 86.95 | 0.30 | 1.26 | 88.51 | 5.54 | 6.7% |
| 900 | 88.15 | 92.46 | 0.32 | 1.34 | 94.12 | 5.97 | 6.8% |
| 950 | 93.33 | 97.96 | 0.34 | 1.42 | 99.72 | 6.39 | 6.8% |
| 1,000 | 98.51 | 103.46 | 0.35 | 1.49 | 105.30 | 6.79 | 6.9% |
| 1,100 | 108.86 | 114.47 | 0.39 | 1.65 | 116.51 | 7.65 | 7.0% |
| 1,200 | 119.22 | 125.47 | 0.42 | 1.81 | 127.70 | 8.48 | 7.1% |
| 1,300 | 129.58 | 136.48 | 0.46 | 1.97 | 138.91 | 9.33 | 7.2% |
| 1,400 | 139.94 | 147.49 | 0.49 | 2.13 | 150.11 | 10.17 | 7.3% |
| 1,500 | 150.30 | 158.49 | 0.53 | 2.29 | 161.31 | 11.01 | 7.3% |
| 1,600 | 160.65 | 169.50 | 0.56 | 2.45 | 172.51 | 11.86 | 7.4% |
| 1,700 | 171.01 | 180.50 | 0.60 | 2.61 | 183.71 | 12.70 | 7.4% |
| 1,800 | 181.37 | 191.51 | 0.64 | 2.77 | 194.92 | 13.55 | 7.5% |
| 1,900 | 191.73 | 202.52 | 0.67 | 2.93 | 206.12 | 14.39 | 7.5% |
| 2,000 | 202.09 | 213.52 | 0.71 | 3.08 | 217.31 | 15.22 | 7.5% |
| 2,200 | 222.80 | 235.53 | 0.78 | 3.40 | 239.71 | 16.91 | 7.6% |
| 2,400 | 243.52 | 257.55 | 0.85 | 3.72 | 262.12 | 18.60 | 7.6% |
| 2,600 | 264.23 | 279.56 | 0.92 | 4.04 | 284.52 | 20.29 | 7.7% |
| 2,800 | 284.95 | 301.57 | 0.99 | 4.36 | 306.92 | 21.97 | 7.7% |
| 3,000 | 305.67 | 323.58 | 1.06 | 4.67 | 329.31 | 23.64 | 7.7% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**E-12 Winter (November-April)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|
| | | Components of Proposed Bill | | | | Change | |
| Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | (A) x $0.000353 | [(C) + (D)] x 0.0144 | (C) + (D) + (E) | (F) - (B) | (G) / (B) |
| 200 | 22.29 | 26.34 | 0.07 | 0.38 | 26.79 | 4.50 | 20.2% |
| 250 | 25.99 | 29.84 | 0.09 | 0.43 | 30.36 | 4.37 | 16.8% |
| 300 | 29.68 | 33.34 | 0.11 | 0.48 | 33.93 | 4.25 | 14.3% |
| 350 | 33.38 | 36.84 | 0.12 | 0.53 | 37.49 | 4.11 | 12.3% |
| 400 | 37.08 | 40.35 | 0.14 | 0.58 | 41.07 | 3.99 | 10.8% |
| 450 | 40.77 | 43.85 | 0.16 | 0.63 | 44.64 | 3.87 | 9.5% |
| 500 | 44.47 | 47.35 | 0.18 | 0.68 | 48.21 | 3.74 | 8.4% |
| 550 | 48.17 | 50.85 | 0.19 | 0.73 | 51.77 | 3.60 | 7.5% |
| 600 | 51.86 | 54.35 | 0.21 | 0.79 | 55.35 | 3.49 | 6.7% |
| 650 | 55.56 | 57.86 | 0.23 | 0.84 | 58.93 | 3.37 | 6.1% |
| 700 | 59.26 | 61.36 | 0.25 | 0.89 | 62.50 | 3.24 | 5.5% |
| 750 | 62.96 | 64.86 | 0.26 | 0.94 | 66.06 | 3.10 | 4.9% |
| 800 | 66.65 | 68.36 | 0.28 | 0.99 | 69.63 | 2.98 | 4.5% |
| 850 | 70.35 | 71.86 | 0.30 | 1.04 | 73.20 | 2.85 | 4.1% |
| 900 | 74.05 | 75.37 | 0.32 | 1.09 | 76.78 | 2.73 | 3.7% |
| 950 | 77.74 | 78.87 | 0.34 | 1.14 | 80.35 | 2.61 | 3.4% |
| 1,000 | 81.44 | 82.37 | 0.35 | 1.19 | 83.91 | 2.47 | 3.0% |
| 1,100 | 88.83 | 89.37 | 0.39 | 1.29 | 91.05 | 2.22 | 2.5% |
| 1,200 | 96.23 | 96.38 | 0.42 | 1.39 | 98.19 | 1.96 | 2.0% |
| 1,300 | 103.62 | 103.38 | 0.46 | 1.50 | 105.34 | 1.72 | 1.7% |
| 1,400 | 111.02 | 110.39 | 0.49 | 1.60 | 112.48 | 1.46 | 1.3% |
| 1,500 | 118.41 | 117.39 | 0.53 | 1.70 | 119.62 | 1.21 | 1.0% |
| 1,600 | 125.80 | 124.39 | 0.56 | 1.80 | 126.75 | 0.95 | 0.8% |
| 1,700 | 133.20 | 131.40 | 0.60 | 1.90 | 133.90 | 0.70 | 0.5% |
| 1,800 | 140.59 | 138.40 | 0.64 | 2.00 | 141.04 | 0.45 | 0.3% |
| 1,900 | 147.99 | 145.41 | 0.67 | 2.10 | 148.18 | 0.19 | 0.1% |
| 2,000 | 155.38 | 152.41 | 0.71 | 2.20 | 155.32 | (0.06) | 0.0% |
| 2,200 | 170.17 | 166.42 | 0.78 | 2.41 | 169.61 | (0.56) | -0.3% |
| 2,400 | 184.96 | 180.43 | 0.85 | 2.61 | 183.89 | (1.07) | -0.6% |
| 2,600 | 199.74 | 194.43 | 0.92 | 2.81 | 198.16 | (1.58) | -0.8% |
| 2,800 | 214.53 | 208.44 | 0.99 | 3.02 | 212.45 | (2.08) | -1.0% |
| 3,000 | 229.32 | 222.45 | 1.06 | 3.22 | 226.73 | (2.59) | -1.1% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**E-12 Summer (May - October)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|
| | | Components of Proposed Bill | | | | Change | |
| Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | (A) x $0.000353 | [(C) + (D)] x 0.0144 | (C) + (D) + (E) | (F) - (B) | (G) / (B) |
| 200 | 22.25 | 29.61 | 0.07 | 0.43 | 30.11 | 7.86 | 35.3% |
| 250 | 25.94 | 33.93 | 0.09 | 0.49 | 34.51 | 8.57 | 33.0% |
| 300 | 29.63 | 38.25 | 0.11 | 0.55 | 38.91 | 9.28 | 31.3% |
| 350 | 33.32 | 42.57 | 0.12 | 0.61 | 43.30 | 9.98 | 30.0% |
| 400 | 37.00 | 46.89 | 0.14 | 0.68 | 47.71 | 10.71 | 28.9% |
| 450 | 42.14 | 51.21 | 0.16 | 0.74 | 52.11 | 9.97 | 23.7% |
| 500 | 47.29 | 55.53 | 0.18 | 0.80 | 56.51 | 9.22 | 19.5% |
| 550 | 52.43 | 59.85 | 0.19 | 0.86 | 60.90 | 8.47 | 16.2% |
| 600 | 57.57 | 64.17 | 0.21 | 0.93 | 65.31 | 7.74 | 13.4% |
| 650 | 62.71 | 68.49 | 0.23 | 0.99 | 69.71 | 7.00 | 11.2% |
| 700 | 67.85 | 72.81 | 0.25 | 1.05 | 74.11 | 6.26 | 9.2% |
| 750 | 72.99 | 77.13 | 0.26 | 1.11 | 78.50 | 5.51 | 7.5% |
| 800 | 78.13 | 81.45 | 0.28 | 1.18 | 82.91 | 4.78 | 6.1% |
| 850 | 84.12 | 86.95 | 0.30 | 1.26 | 88.51 | 4.39 | 5.2% |
| 900 | 90.12 | 92.46 | 0.32 | 1.34 | 94.12 | 4.00 | 4.4% |
| 950 | 96.11 | 97.96 | 0.34 | 1.42 | 99.72 | 3.61 | 3.8% |
| 1,000 | 102.11 | 103.46 | 0.35 | 1.49 | 105.30 | 3.19 | 3.1% |
| 1,100 | 114.10 | 114.47 | 0.39 | 1.65 | 116.51 | 2.41 | 2.1% |
| 1,200 | 126.09 | 125.47 | 0.42 | 1.81 | 127.70 | 1.61 | 1.3% |
| 1,300 | 138.08 | 136.48 | 0.46 | 1.97 | 138.91 | 0.83 | 0.6% |
| 1,400 | 150.07 | 147.49 | 0.49 | 2.13 | 150.11 | 0.04 | 0.0% |
| 1,500 | 162.07 | 158.49 | 0.53 | 2.29 | 161.31 | (0.76) | -0.5% |
| 1,600 | 174.06 | 169.50 | 0.56 | 2.45 | 172.51 | (1.55) | -0.9% |
| 1,700 | 186.05 | 180.50 | 0.60 | 2.61 | 183.71 | (2.34) | -1.3% |
| 1,800 | 198.04 | 191.51 | 0.64 | 2.77 | 194.92 | (3.12) | -1.6% |
| 1,900 | 210.03 | 202.52 | 0.67 | 2.93 | 206.12 | (3.91) | -1.9% |
| 2,000 | 222.02 | 213.52 | 0.71 | 3.08 | 217.31 | (4.71) | -2.1% |
| 2,200 | 246.00 | 235.53 | 0.78 | 3.40 | 239.71 | (6.29) | -2.6% |
| 2,400 | 269.98 | 257.55 | 0.85 | 3.72 | 262.12 | (7.86) | -2.9% |
| 2,600 | 293.97 | 279.56 | 0.92 | 4.04 | 284.52 | (9.45) | -3.2% |
| 2,800 | 317.95 | 301.57 | 0.99 | 4.36 | 306.92 | (11.03) | -3.5% |
| 3,000 | 341.93 | 323.58 | 1.06 | 4.67 | 329.31 | (12.62) | -3.7% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**EC-1 Winter (November-April)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Components of Proposed Bill | | | | Change | |
| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | | | (C) x $0.000353 | [(E) + (F)] x 0.0144 | (E) + (F) + (G) | (H) - (D) | (I) / (D) |
| 3 | 20% | 438 | 45.09 | 52.04 | 0.15 | 0.75 | 52.94 | 7.85 | 17.4% |
| 3 | 30% | 657 | 52.05 | 58.66 | 0.23 | 0.85 | 59.74 | 7.69 | 14.8% |
| 3 | 40% | 876 | 59.00 | 65.29 | 0.31 | 0.94 | 66.54 | 7.54 | 12.8% |
| 3 | 50% | 1,095 | 65.96 | 71.91 | 0.39 | 1.04 | 73.34 | 7.38 | 11.2% |
| 3 | 75% | 1,643 | 83.36 | 88.49 | 0.58 | 1.28 | 90.35 | 6.99 | 8.4% |
| 5 | 20% | 730 | 68.48 | 76.87 | 0.26 | 1.11 | 78.24 | 9.76 | 14.3% |
| 5 | 30% | 1,095 | 80.08 | 87.91 | 0.39 | 1.27 | 89.57 | 9.49 | 11.9% |
| 5 | 40% | 1,460 | 91.67 | 98.96 | 0.52 | 1.43 | 100.91 | 9.24 | 10.1% |
| 5 | 50% | 1,825 | 103.26 | 110.00 | 0.64 | 1.59 | 112.23 | 8.97 | 8.7% |
| 5 | 75% | 2,738 | 132.26 | 137.61 | 0.97 | 2.00 | 140.58 | 8.32 | 6.3% |
| 8 | 20% | 1,168 | 103.58 | 114.12 | 0.41 | 1.65 | 116.18 | 12.60 | 12.2% |
| 8 | 30% | 1,752 | 122.12 | 131.79 | 0.62 | 1.91 | 134.32 | 12.20 | 10.0% |
| 8 | 40% | 2,336 | 140.67 | 149.45 | 0.82 | 2.16 | 152.43 | 11.76 | 8.4% |
| 8 | 50% | 2,920 | 159.22 | 167.12 | 1.03 | 2.42 | 170.57 | 11.35 | 7.1% |
| 8 | 75% | 4,380 | 205.59 | 211.29 | 1.55 | 3.06 | 215.90 | 10.31 | 5.0% |
| 10 | 20% | 1,460 | 126.97 | 138.96 | 0.52 | 2.01 | 141.49 | 14.52 | 11.4% |
| 10 | 30% | 2,190 | 150.15 | 161.04 | 0.77 | 2.33 | 164.14 | 13.99 | 9.3% |
| 10 | 40% | 2,920 | 173.34 | 183.12 | 1.03 | 2.65 | 186.80 | 13.46 | 7.8% |
| 10 | 50% | 3,650 | 196.52 | 205.20 | 1.29 | 2.97 | 209.46 | 12.94 | 6.6% |
| 10 | 75% | 5,475 | 254.49 | 260.41 | 1.93 | 3.78 | 266.12 | 11.63 | 4.6% |
| 12 | 20% | 1,752 | 150.36 | 163.79 | 0.62 | 2.37 | 166.78 | 16.42 | 10.9% |
| 12 | 30% | 2,628 | 178.19 | 190.29 | 0.93 | 2.75 | 193.97 | 15.78 | 8.9% |
| 12 | 40% | 3,504 | 206.01 | 216.79 | 1.24 | 3.14 | 221.17 | 15.16 | 7.4% |
| 12 | 50% | 4,380 | 233.83 | 243.29 | 1.55 | 3.53 | 248.37 | 14.54 | 6.2% |
| 12 | 75% | 6,570 | 303.38 | 309.53 | 2.32 | 4.49 | 316.34 | 12.96 | 4.3% |
| 15 | 20% | 2,190 | 185.45 | 201.04 | 0.77 | 2.91 | 204.72 | 19.27 | 10.4% |
| 15 | 30% | 3,285 | 220.23 | 234.16 | 1.16 | 3.39 | 238.71 | 18.48 | 8.4% |
| 15 | 40% | 4,380 | 255.01 | 267.29 | 1.55 | 3.87 | 272.71 | 17.70 | 6.9% |
| 15 | 50% | 5,475 | 289.79 | 300.41 | 1.93 | 4.35 | 306.69 | 16.90 | 5.8% |
| 15 | 75% | 8,213 | 376.74 | 383.23 | 2.90 | 5.56 | 391.69 | 14.95 | 4.0% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**EC-1 Summer (May-October)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Components of Proposed Bill | | | | Change | |
| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | | | (C) x $0.000353 | [(E) + (F)] x 0.0144 | (E) + (F) + (G) | (H) - (D) | (I) / (D) |
| 3 | 20% | 438 | 56.28 | 65.45 | 0.15 | 0.94 | 66.54 | 10.26 | 18.2% |
| 3 | 30% | 657 | 64.66 | 74.29 | 0.23 | 1.07 | 75.59 | 10.93 | 16.9% |
| 3 | 40% | 876 | 73.04 | 83.12 | 0.31 | 1.20 | 84.63 | 11.59 | 15.9% |
| 3 | 50% | 1,095 | 81.43 | 91.95 | 0.39 | 1.33 | 93.67 | 12.24 | 15.0% |
| 3 | 75% | 1,643 | 102.40 | 114.05 | 0.58 | 1.65 | 116.28 | 13.88 | 13.6% |
| 5 | 20% | 730 | 87.14 | 99.23 | 0.26 | 1.43 | 100.92 | 13.78 | 15.8% |
| 5 | 30% | 1,095 | 101.11 | 113.95 | 0.39 | 1.65 | 115.99 | 14.88 | 14.7% |
| 5 | 40% | 1,460 | 115.07 | 128.67 | 0.52 | 1.86 | 131.05 | 15.98 | 13.9% |
| 5 | 50% | 1,825 | 129.04 | 143.39 | 0.64 | 2.07 | 146.10 | 17.06 | 13.2% |
| 5 | 75% | 2,738 | 163.98 | 180.21 | 0.97 | 2.61 | 183.79 | 19.81 | 12.1% |
| 8 | 20% | 1,168 | 133.42 | 149.89 | 0.41 | 2.16 | 152.46 | 19.04 | 14.3% |
| 8 | 30% | 1,752 | 155.77 | 173.45 | 0.62 | 2.51 | 176.58 | 20.81 | 13.4% |
| 8 | 40% | 2,336 | 178.12 | 197.00 | 0.82 | 2.85 | 200.67 | 22.55 | 12.7% |
| 8 | 50% | 2,920 | 200.47 | 220.55 | 1.03 | 3.19 | 224.77 | 24.30 | 12.1% |
| 8 | 75% | 4,380 | 256.34 | 279.43 | 1.55 | 4.05 | 285.03 | 28.69 | 11.2% |
| 10 | 20% | 1,460 | 164.27 | 183.67 | 0.52 | 2.65 | 186.84 | 22.57 | 13.7% |
| 10 | 30% | 2,190 | 192.21 | 213.11 | 0.77 | 3.08 | 216.96 | 24.75 | 12.9% |
| 10 | 40% | 2,920 | 220.15 | 242.55 | 1.03 | 3.51 | 247.09 | 26.94 | 12.2% |
| 10 | 50% | 3,650 | 248.09 | 271.99 | 1.29 | 3.94 | 277.22 | 29.13 | 11.7% |
| 10 | 75% | 5,475 | 317.93 | 345.59 | 1.93 | 5.00 | 352.52 | 34.59 | 10.9% |
| 12 | 20% | 1,752 | 195.13 | 217.45 | 0.62 | 3.14 | 221.21 | 26.08 | 13.4% |
| 12 | 30% | 2,628 | 228.65 | 252.77 | 0.93 | 3.65 | 257.35 | 28.70 | 12.6% |
| 12 | 40% | 3,504 | 262.18 | 288.10 | 1.24 | 4.17 | 293.51 | 31.33 | 11.9% |
| 12 | 50% | 4,380 | 295.70 | 323.43 | 1.55 | 4.68 | 329.66 | 33.96 | 11.5% |
| 12 | 75% | 6,570 | 379.51 | 411.75 | 2.32 | 5.96 | 420.03 | 40.52 | 10.7% |
| 15 | 20% | 2,190 | 241.41 | 268.11 | 0.77 | 3.87 | 272.75 | 31.34 | 13.0% |
| 15 | 30% | 3,285 | 283.32 | 312.27 | 1.16 | 4.51 | 317.94 | 34.62 | 12.2% |
| 15 | 40% | 4,380 | 325.22 | 356.43 | 1.55 | 5.15 | 363.13 | 37.91 | 11.7% |
| 15 | 50% | 5,475 | 367.13 | 400.59 | 1.93 | 5.80 | 408.32 | 41.19 | 11.2% |
| 15 | 75% | 8,213 | 471.91 | 511.01 | 2.90 | 7.40 | 521.31 | 49.40 | 10.5% |

EC-1 Summer Average Energy On-Peak: 42%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**ET-1 Winter (November-April)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|
| | | Components of Proposed Bill | | | | Change | |
| Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | (A) x $0.000353 | [(C) + (D)] x 0.0144 | (C) + (D) + (E) | (F) - (B) | (G) / (B) |
| 200 | 27.17 | 28.12 | 0.07 | 0.41 | 28.60 | 1.43 | 5.3% |
| 250 | 30.22 | 31.51 | 0.09 | 0.46 | 32.06 | 1.84 | 6.1% |
| 300 | 33.26 | 34.90 | 0.11 | 0.50 | 35.51 | 2.25 | 6.8% |
| 350 | 36.30 | 38.29 | 0.12 | 0.55 | 38.96 | 2.66 | 7.3% |
| 400 | 39.35 | 41.69 | 0.14 | 0.60 | 42.43 | 3.08 | 7.8% |
| 450 | 42.39 | 45.08 | 0.16 | 0.65 | 45.89 | 3.50 | 8.3% |
| 500 | 45.44 | 48.47 | 0.18 | 0.70 | 49.35 | 3.91 | 8.6% |
| 550 | 48.48 | 51.86 | 0.19 | 0.75 | 52.80 | 4.32 | 8.9% |
| 600 | 51.52 | 55.25 | 0.21 | 0.80 | 56.26 | 4.74 | 9.2% |
| 650 | 54.57 | 58.65 | 0.23 | 0.85 | 59.73 | 5.16 | 9.5% |
| 700 | 57.61 | 62.04 | 0.25 | 0.90 | 63.19 | 5.58 | 9.7% |
| 750 | 60.65 | 65.43 | 0.26 | 0.95 | 66.64 | 5.99 | 9.9% |
| 800 | 63.70 | 68.82 | 0.28 | 1.00 | 70.10 | 6.40 | 10.0% |
| 850 | 66.74 | 72.21 | 0.30 | 1.04 | 73.55 | 6.81 | 10.2% |
| 900 | 69.78 | 75.61 | 0.32 | 1.09 | 77.02 | 7.24 | 10.4% |
| 950 | 72.83 | 79.00 | 0.34 | 1.14 | 80.48 | 7.65 | 10.5% |
| 1,000 | 75.87 | 82.39 | 0.35 | 1.19 | 83.93 | 8.06 | 10.6% |
| 1,100 | 81.96 | 89.17 | 0.39 | 1.29 | 90.85 | 8.89 | 10.8% |
| 1,200 | 88.05 | 95.96 | 0.42 | 1.39 | 97.77 | 9.72 | 11.0% |
| 1,300 | 94.13 | 102.74 | 0.46 | 1.49 | 104.69 | 10.56 | 11.2% |
| 1,400 | 100.22 | 109.53 | 0.49 | 1.58 | 111.60 | 11.38 | 11.4% |
| 1,500 | 106.31 | 116.31 | 0.53 | 1.68 | 118.52 | 12.21 | 11.5% |
| 1,600 | 112.39 | 123.09 | 0.56 | 1.78 | 125.43 | 13.04 | 11.6% |
| 1,700 | 118.48 | 129.88 | 0.60 | 1.88 | 132.36 | 13.88 | 11.7% |
| 1,800 | 124.57 | 136.66 | 0.64 | 1.98 | 139.28 | 14.71 | 11.8% |
| 1,900 | 130.65 | 143.45 | 0.67 | 2.08 | 146.20 | 15.55 | 11.9% |
| 2,000 | 136.74 | 150.23 | 0.71 | 2.17 | 153.11 | 16.37 | 12.0% |
| 2,200 | 148.92 | 163.80 | 0.78 | 2.37 | 166.95 | 18.03 | 12.1% |
| 2,400 | 161.09 | 177.37 | 0.85 | 2.57 | 180.79 | 19.70 | 12.2% |
| 2,600 | 173.26 | 190.93 | 0.92 | 2.76 | 194.61 | 21.35 | 12.3% |
| 2,800 | 185.44 | 204.50 | 0.99 | 2.96 | 208.45 | 23.01 | 12.4% |
| 3,000 | 197.61 | 218.07 | 1.06 | 3.16 | 222.29 | 24.68 | 12.5% |

ET-1 Winter Average Energy On-Peak: 30%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**ET-1 Summer (May - October)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|
| | | Components of Proposed Bill | | | | Change | |
| Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | (A) x $0.000353 | [(C) + (D)] x 0.0144 | (C) + (D) + (E) | (F) - (B) | (G) / (B) |
| 200 | 30.21 | 31.62 | 0.07 | 0.46 | 32.15 | 1.94 | 6.4% |
| 250 | 34.01 | 35.88 | 0.09 | 0.52 | 36.49 | 2.48 | 7.3% |
| 300 | 37.81 | 40.15 | 0.11 | 0.58 | 40.84 | 3.03 | 8.0% |
| 350 | 41.61 | 44.42 | 0.12 | 0.64 | 45.18 | 3.57 | 8.6% |
| 400 | 45.41 | 48.68 | 0.14 | 0.70 | 49.52 | 4.11 | 9.1% |
| 450 | 49.22 | 52.95 | 0.16 | 0.76 | 53.87 | 4.65 | 9.4% |
| 500 | 53.02 | 57.22 | 0.18 | 0.83 | 58.23 | 5.21 | 9.8% |
| 550 | 56.82 | 61.48 | 0.19 | 0.89 | 62.56 | 5.74 | 10.1% |
| 600 | 60.62 | 65.75 | 0.21 | 0.95 | 66.91 | 6.29 | 10.4% |
| 650 | 64.42 | 70.01 | 0.23 | 1.01 | 71.25 | 6.83 | 10.6% |
| 700 | 68.22 | 74.28 | 0.25 | 1.07 | 75.60 | 7.38 | 10.8% |
| 750 | 72.03 | 78.55 | 0.26 | 1.13 | 79.94 | 7.91 | 11.0% |
| 800 | 75.83 | 82.81 | 0.28 | 1.20 | 84.29 | 8.46 | 11.2% |
| 850 | 79.63 | 87.08 | 0.30 | 1.26 | 88.64 | 9.01 | 11.3% |
| 900 | 83.43 | 91.35 | 0.32 | 1.32 | 92.99 | 9.56 | 11.5% |
| 950 | 87.23 | 95.61 | 0.34 | 1.38 | 97.33 | 10.10 | 11.6% |
| 1,000 | 91.03 | 99.88 | 0.35 | 1.44 | 101.67 | 10.64 | 11.7% |
| 1,100 | 98.64 | 108.41 | 0.39 | 1.57 | 110.37 | 11.73 | 11.9% |
| 1,200 | 106.24 | 116.95 | 0.42 | 1.69 | 119.06 | 12.82 | 12.1% |
| 1,300 | 113.84 | 125.48 | 0.46 | 1.81 | 127.75 | 13.91 | 12.2% |
| 1,400 | 121.45 | 134.01 | 0.49 | 1.94 | 136.44 | 14.99 | 12.3% |
| 1,500 | 129.05 | 142.55 | 0.53 | 2.06 | 145.14 | 16.09 | 12.5% |
| 1,600 | 136.65 | 151.08 | 0.56 | 2.18 | 153.82 | 17.17 | 12.6% |
| 1,700 | 144.26 | 159.61 | 0.60 | 2.31 | 162.52 | 18.26 | 12.7% |
| 1,800 | 151.86 | 168.14 | 0.64 | 2.43 | 171.21 | 19.35 | 12.7% |
| 1,900 | 159.46 | 176.68 | 0.67 | 2.55 | 179.90 | 20.44 | 12.8% |
| 2,000 | 167.07 | 185.21 | 0.71 | 2.68 | 188.60 | 21.53 | 12.9% |
| 2,200 | 182.27 | 202.28 | 0.78 | 2.92 | 205.98 | 23.71 | 13.0% |
| 2,400 | 197.48 | 219.34 | 0.85 | 3.17 | 223.36 | 25.88 | 13.1% |
| 2,600 | 212.69 | 236.41 | 0.92 | 3.42 | 240.75 | 28.06 | 13.2% |
| 2,800 | 227.90 | 253.47 | 0.99 | 3.66 | 258.12 | 30.22 | 13.3% |
| 3,000 | 243.10 | 270.54 | 1.06 | 3.91 | 275.51 | 32.41 | 13.3% |

ET-1 Summer Average Energy On-Peak: 40%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**ECT-1R Winter (November-April)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Components of Proposed Bill | | | | Change | |
| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | | | (C) x $0.000353 | [(E) + (F)] x 0.0144 | (E) + (F) + (G) | (H) - (D) | (I) / (D) |
| 3 | 20% | 438 | 51.93 | 52.04 | 0.15 | 0.75 | 52.94 | 1.01 | 1.9% |
| 3 | 30% | 657 | 58.23 | 58.66 | 0.23 | 0.85 | 59.74 | 1.51 | 2.6% |
| 3 | 40% | 876 | 64.53 | 65.29 | 0.31 | 0.94 | 66.54 | 2.01 | 3.1% |
| 3 | 50% | 1,095 | 70.82 | 71.91 | 0.39 | 1.04 | 73.34 | 2.52 | 3.6% |
| 3 | 75% | 1,643 | 86.59 | 88.49 | 0.58 | 1.28 | 90.35 | 3.76 | 4.3% |
| 5 | 20% | 730 | 76.55 | 76.87 | 0.26 | 1.11 | 78.24 | 1.69 | 2.2% |
| 5 | 30% | 1,095 | 87.04 | 87.91 | 0.39 | 1.27 | 89.57 | 2.53 | 2.9% |
| 5 | 40% | 1,460 | 97.54 | 98.96 | 0.52 | 1.43 | 100.91 | 3.37 | 3.5% |
| 5 | 50% | 1,825 | 108.04 | 110.00 | 0.64 | 1.59 | 112.23 | 4.19 | 3.9% |
| 5 | 75% | 2,738 | 134.30 | 137.61 | 0.97 | 2.00 | 140.58 | 6.28 | 4.7% |
| 8 | 20% | 1,168 | 113.47 | 114.12 | 0.41 | 1.65 | 116.18 | 2.71 | 2.4% |
| 8 | 30% | 1,752 | 130.27 | 131.79 | 0.62 | 1.91 | 134.32 | 4.05 | 3.1% |
| 8 | 40% | 2,336 | 147.07 | 149.45 | 0.82 | 2.16 | 152.43 | 5.36 | 3.6% |
| 8 | 50% | 2,920 | 163.87 | 167.12 | 1.03 | 2.42 | 170.57 | 6.70 | 4.1% |
| 8 | 75% | 4,380 | 205.86 | 211.29 | 1.55 | 3.06 | 215.90 | 10.04 | 4.9% |
| 10 | 20% | 1,460 | 138.09 | 138.96 | 0.52 | 2.01 | 141.49 | 3.40 | 2.5% |
| 10 | 30% | 2,190 | 159.09 | 161.04 | 0.77 | 2.33 | 164.14 | 5.05 | 3.2% |
| 10 | 40% | 2,920 | 180.09 | 183.12 | 1.03 | 2.65 | 186.80 | 6.71 | 3.7% |
| 10 | 50% | 3,650 | 201.08 | 205.20 | 1.29 | 2.97 | 209.46 | 8.38 | 4.2% |
| 10 | 75% | 5,475 | 253.57 | 260.41 | 1.93 | 3.78 | 266.12 | 12.55 | 4.9% |
| 12 | 20% | 1,752 | 162.71 | 163.79 | 0.62 | 2.37 | 166.78 | 4.07 | 2.5% |
| 12 | 30% | 2,628 | 187.91 | 190.29 | 0.93 | 2.75 | 193.97 | 6.06 | 3.2% |
| 12 | 40% | 3,504 | 213.10 | 216.79 | 1.24 | 3.14 | 221.17 | 8.07 | 3.8% |
| 12 | 50% | 4,380 | 238.30 | 243.29 | 1.55 | 3.53 | 248.37 | 10.07 | 4.2% |
| 12 | 75% | 6,570 | 301.29 | 309.53 | 2.32 | 4.49 | 316.34 | 15.05 | 5.0% |
| 15 | 20% | 2,190 | 199.64 | 201.04 | 0.77 | 2.91 | 204.72 | 5.08 | 2.5% |
| 15 | 30% | 3,285 | 231.13 | 234.16 | 1.16 | 3.39 | 238.71 | 7.58 | 3.3% |
| 15 | 40% | 4,380 | 262.63 | 267.29 | 1.55 | 3.87 | 272.71 | 10.08 | 3.8% |
| 15 | 50% | 5,475 | 294.12 | 300.41 | 1.93 | 4.35 | 306.69 | 12.57 | 4.3% |
| 15 | 75% | 8,213 | 372.88 | 383.23 | 2.90 | 5.56 | 391.69 | 18.81 | 5.0% |

ECT-1R Winter Average Energy On-Peak: 31%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical Residential Bill Analysis**
**ECT-1R Summer (May-October)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Components of Proposed Bill | | | | Change | |
| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | | | (C) x $0.000353 | [(E) + (F)] x 0.0144 | (E) + (F) + (G) | (H) - (D) | (I) / (D) |
| 3 | 20% | 438 | 63.51 | 65.15 | 0.15 | 0.94 | 66.24 | 2.73 | 4.3% |
| 3 | 30% | 657 | 70.76 | 73.83 | 0.23 | 1.07 | 75.13 | 4.37 | 6.2% |
| 3 | 40% | 876 | 78.02 | 82.50 | 0.31 | 1.19 | 84.00 | 5.98 | 7.7% |
| 3 | 50% | 1,095 | 85.28 | 91.18 | 0.39 | 1.32 | 92.89 | 7.61 | 8.9% |
| 3 | 75% | 1,643 | 103.44 | 112.90 | 0.58 | 1.63 | 115.11 | 11.67 | 11.3% |
| 5 | 20% | 730 | 95.84 | 98.72 | 0.26 | 1.43 | 100.41 | 4.57 | 4.8% |
| 5 | 30% | 1,095 | 107.94 | 113.18 | 0.39 | 1.64 | 115.21 | 7.27 | 6.7% |
| 5 | 40% | 1,460 | 120.03 | 127.65 | 0.52 | 1.85 | 130.02 | 9.99 | 8.3% |
| 5 | 50% | 1,825 | 132.13 | 142.11 | 0.64 | 2.06 | 144.81 | 12.68 | 9.6% |
| 5 | 75% | 2,738 | 162.39 | 178.29 | 0.97 | 2.58 | 181.84 | 19.45 | 12.0% |
| 8 | 20% | 1,168 | 144.35 | 149.08 | 0.41 | 2.15 | 151.64 | 7.29 | 5.1% |
| 8 | 30% | 1,752 | 163.70 | 172.22 | 0.62 | 2.49 | 175.33 | 11.63 | 7.1% |
| 8 | 40% | 2,336 | 183.06 | 195.36 | 0.82 | 2.82 | 199.00 | 15.94 | 8.7% |
| 8 | 50% | 2,920 | 202.41 | 218.50 | 1.03 | 3.16 | 222.69 | 20.28 | 10.0% |
| 8 | 75% | 4,380 | 250.79 | 276.36 | 1.55 | 4.00 | 281.91 | 31.12 | 12.4% |
| 10 | 20% | 1,460 | 176.68 | 182.65 | 0.52 | 2.64 | 185.81 | 9.13 | 5.2% |
| 10 | 30% | 2,190 | 200.88 | 211.57 | 0.77 | 3.06 | 215.40 | 14.52 | 7.2% |
| 10 | 40% | 2,920 | 225.07 | 240.50 | 1.03 | 3.48 | 245.01 | 19.94 | 8.9% |
| 10 | 50% | 3,650 | 249.26 | 269.43 | 1.29 | 3.90 | 274.62 | 25.36 | 10.2% |
| 10 | 75% | 5,475 | 309.74 | 341.75 | 1.93 | 4.95 | 348.63 | 38.89 | 12.6% |
| 12 | 20% | 1,752 | 209.02 | 216.22 | 0.62 | 3.12 | 219.96 | 10.94 | 5.2% |
| 12 | 30% | 2,628 | 238.05 | 250.93 | 0.93 | 3.63 | 255.49 | 17.44 | 7.3% |
| 12 | 40% | 3,504 | 267.08 | 285.65 | 1.24 | 4.13 | 291.02 | 23.94 | 9.0% |
| 12 | 50% | 4,380 | 296.11 | 320.36 | 1.55 | 4.64 | 326.55 | 30.44 | 10.3% |
| 12 | 75% | 6,570 | 368.69 | 407.14 | 2.32 | 5.90 | 415.36 | 46.67 | 12.7% |
| 15 | 20% | 2,190 | 257.53 | 266.57 | 0.77 | 3.85 | 271.19 | 13.66 | 5.3% |
| 15 | 30% | 3,285 | 293.82 | 309.97 | 1.16 | 4.48 | 315.61 | 21.79 | 7.4% |
| 15 | 40% | 4,380 | 330.10 | 353.36 | 1.55 | 5.11 | 360.02 | 29.92 | 9.1% |
| 15 | 50% | 5,475 | 366.39 | 396.75 | 1.93 | 5.74 | 404.42 | 38.03 | 10.4% |
| 15 | 75% | 8,213 | 457.13 | 505.25 | 2.90 | 7.32 | 515.47 | 58.34 | 12.8% |

ECT-1R Summer Average Energy On-Peak: 38%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical General Service Bill Analysis**
**E-30 Summer (May - October)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|
| | | Components of Proposed Bill | | | | Change | |
| Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | (A) x $0.000353 | [(C) + (D)] x 0.0144 | (C) + (D) + (E) | (F) - (B) | (G) / (B) |
| 30 | 9.00 | 11.31 | 0.01 | 0.16 | 11.48 | 2.48 | 27.6% |
| 40 | 9.92 | 12.22 | 0.01 | 0.18 | 12.41 | 2.49 | 25.1% |
| 50 | 10.83 | 13.13 | 0.02 | 0.19 | 13.34 | 2.51 | 23.2% |
| 60 | 11.75 | 14.03 | 0.02 | 0.20 | 14.25 | 2.50 | 21.3% |
| 70 | 12.67 | 14.94 | 0.02 | 0.22 | 15.18 | 2.51 | 19.8% |
| 80 | 13.58 | 15.85 | 0.03 | 0.23 | 16.11 | 2.53 | 18.6% |
| 90 | 14.50 | 16.76 | 0.03 | 0.24 | 17.03 | 2.53 | 17.4% |
| 100 | 15.42 | 17.67 | 0.04 | 0.26 | 17.97 | 2.55 | 16.5% |
| 125 | 17.71 | 19.94 | 0.04 | 0.29 | 20.27 | 2.56 | 14.5% |
| 150 | 20.00 | 22.22 | 0.05 | 0.32 | 22.59 | 2.59 | 13.0% |
| 175 | 22.29 | 24.49 | 0.06 | 0.35 | 24.90 | 2.61 | 11.7% |
| 200 | 24.59 | 26.76 | 0.07 | 0.39 | 27.22 | 2.63 | 10.7% |
| 225 | 26.88 | 29.03 | 0.08 | 0.42 | 29.53 | 2.65 | 9.9% |
| 250 | 29.17 | 31.31 | 0.09 | 0.45 | 31.85 | 2.68 | 9.2% |
| 275 | 31.46 | 33.58 | 0.10 | 0.48 | 34.16 | 2.70 | 8.6% |
| 300 | 33.75 | 35.85 | 0.11 | 0.52 | 36.48 | 2.73 | 8.1% |
| 325 | 36.05 | 38.13 | 0.11 | 0.55 | 38.79 | 2.74 | 7.6% |
| 350 | 38.34 | 40.40 | 0.12 | 0.58 | 41.10 | 2.76 | 7.2% |
| 375 | 40.63 | 42.67 | 0.13 | 0.62 | 43.42 | 2.79 | 6.9% |
| 400 | 42.92 | 44.94 | 0.14 | 0.65 | 45.73 | 2.81 | 6.5% |
| 425 | 45.21 | 47.22 | 0.15 | 0.68 | 48.05 | 2.84 | 6.3% |
| 450 | 47.51 | 49.49 | 0.16 | 0.71 | 50.36 | 2.85 | 6.0% |
| 475 | 49.80 | 51.76 | 0.17 | 0.75 | 52.68 | 2.88 | 5.8% |
| 500 | 52.09 | 54.04 | 0.18 | 0.78 | 55.00 | 2.91 | 5.6% |
| 600 | 61.26 | 63.13 | 0.21 | 0.91 | 64.25 | 2.99 | 4.9% |
| 700 | 70.43 | 72.22 | 0.25 | 1.04 | 73.51 | 3.08 | 4.4% |
| 800 | 79.59 | 81.31 | 0.28 | 1.17 | 82.76 | 3.17 | 4.0% |
| 900 | 88.76 | 90.40 | 0.32 | 1.31 | 92.03 | 3.27 | 3.7% |
| 1,000 | 97.93 | 99.49 | 0.35 | 1.44 | 101.28 | 3.35 | 3.4% |
| 1,500 | 143.77 | 144.95 | 0.53 | 2.09 | 147.57 | 3.80 | 2.6% |
| 2,000 | 189.61 | 190.40 | 0.71 | 2.75 | 193.86 | 4.25 | 2.2% |
| 2,500 | 235.45 | 235.86 | 0.88 | 3.41 | 240.15 | 4.70 | 2.0% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical General Service Bill Analysis**
**E-30 Winter (November-April)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|
| | | Components of Proposed Bill | | | | Change | |
| Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | (A) x $0.000353 | [(C) + (D)] x 0.0144 | (C) + (D) + (E) | (F) - (B) | (G) / (B) |
| 30 | 9.30 | 11.61 | 0.01 | 0.17 | 11.79 | 2.49 | 26.8% |
| 40 | 10.32 | 12.62 | 0.01 | 0.18 | 12.81 | 2.49 | 24.1% |
| 50 | 11.34 | 13.63 | 0.02 | 0.20 | 13.85 | 2.51 | 22.1% |
| 60 | 12.36 | 14.63 | 0.02 | 0.21 | 14.86 | 2.50 | 20.2% |
| 70 | 13.38 | 15.64 | 0.02 | 0.23 | 15.89 | 2.51 | 18.8% |
| 80 | 14.39 | 16.65 | 0.03 | 0.24 | 16.92 | 2.53 | 17.6% |
| 90 | 15.41 | 17.66 | 0.03 | 0.25 | 17.94 | 2.53 | 16.4% |
| 100 | 16.43 | 18.67 | 0.04 | 0.27 | 18.98 | 2.55 | 15.5% |
| 125 | 18.97 | 21.19 | 0.04 | 0.31 | 21.54 | 2.57 | 13.5% |
| 150 | 21.52 | 23.72 | 0.05 | 0.34 | 24.11 | 2.59 | 12.0% |
| 175 | 24.06 | 26.24 | 0.06 | 0.38 | 26.68 | 2.62 | 10.9% |
| 200 | 26.61 | 28.76 | 0.07 | 0.42 | 29.25 | 2.64 | 9.9% |
| 225 | 29.15 | 31.28 | 0.08 | 0.45 | 31.81 | 2.66 | 9.1% |
| 250 | 31.70 | 33.81 | 0.09 | 0.49 | 34.39 | 2.69 | 8.5% |
| 275 | 34.24 | 36.33 | 0.10 | 0.52 | 36.95 | 2.71 | 7.9% |
| 300 | 36.79 | 38.85 | 0.11 | 0.56 | 39.52 | 2.73 | 7.4% |
| 325 | 39.33 | 41.38 | 0.11 | 0.60 | 42.09 | 2.76 | 7.0% |
| 350 | 41.88 | 43.90 | 0.12 | 0.63 | 44.65 | 2.77 | 6.6% |
| 375 | 44.42 | 46.42 | 0.13 | 0.67 | 47.22 | 2.80 | 6.3% |
| 400 | 46.97 | 48.94 | 0.14 | 0.71 | 49.79 | 2.82 | 6.0% |
| 425 | 49.51 | 51.47 | 0.15 | 0.74 | 52.36 | 2.85 | 5.8% |
| 450 | 52.06 | 53.99 | 0.16 | 0.78 | 54.93 | 2.87 | 5.5% |
| 475 | 54.60 | 56.51 | 0.17 | 0.82 | 57.50 | 2.90 | 5.3% |
| 500 | 57.15 | 59.04 | 0.18 | 0.85 | 60.07 | 2.92 | 5.1% |
| 600 | 67.32 | 69.13 | 0.21 | 1.00 | 70.34 | 3.02 | 4.5% |
| 700 | 77.50 | 79.22 | 0.25 | 1.14 | 80.61 | 3.11 | 4.0% |
| 800 | 87.68 | 89.31 | 0.28 | 1.29 | 90.88 | 3.20 | 3.6% |
| 900 | 97.86 | 99.40 | 0.32 | 1.44 | 101.16 | 3.30 | 3.4% |
| 1,000 | 108.04 | 109.49 | 0.35 | 1.58 | 111.42 | 3.38 | 3.1% |
| 1,500 | 158.94 | 159.95 | 0.53 | 2.31 | 162.79 | 3.85 | 2.4% |
| 2,000 | 209.83 | 210.40 | 0.71 | 3.04 | 214.15 | 4.32 | 2.1% |
| 2,500 | 260.73 | 260.86 | 0.88 | 3.77 | 265.51 | 4.78 | 1.8% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

**Arizona Public Service Company**

**Typical General Service Bill Analysis**
**E-32 Winter (November-April)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Components of Proposed Bill | | | | Change | |
| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | | | (C) x $0.000353 | [(E) + (F)] x 0.0144 | (E) + (F) + (G) | (H) - (D) | (I) / (D) |
| 10 | 15% | 1,095 | 120.86 | 116.84 | 0.39 | 1.69 | 118.92 | (1.94) | -1.6% |
| 10 | 30% | 2,190 | 221.47 | 216.43 | 0.77 | 3.13 | 220.33 | (1.14) | -0.5% |
| 10 | 45% | 3,285 | 313.78 | 316.02 | 1.16 | 4.57 | 321.75 | 7.97 | 2.5% |
| 10 | 60% | 4,380 | 382.50 | 415.61 | 1.55 | 6.01 | 423.17 | 40.67 | 10.6% |
| 10 | 75% | 5,475 | 451.22 | 515.20 | 1.93 | 7.45 | 524.58 | 73.36 | 16.3% |
| 100 | 15% | 10,950 | 1,165.84 | 1,492.04 | 3.87 | 21.54 | 1,517.45 | 351.61 | 30.2% |
| 100 | 30% | 21,900 | 1,883.63 | 2,234.93 | 7.73 | 32.29 | 2,274.95 | 391.32 | 20.8% |
| 100 | 45% | 32,850 | 2,570.86 | 2,595.19 | 11.60 | 37.54 | 2,644.33 | 73.47 | 2.9% |
| 100 | 60% | 43,800 | 3,258.08 | 2,955.44 | 15.46 | 42.78 | 3,013.68 | (244.40) | -7.5% |
| 100 | 75% | 54,750 | 3,927.76 | 3,315.70 | 19.33 | 48.02 | 3,383.05 | (544.71) | -13.9% |
| 200 | 15% | 21,900 | 2,326.92 | 2,950.06 | 7.73 | 42.59 | 3,000.38 | 673.46 | 28.9% |
| 200 | 30% | 43,800 | 3,704.28 | 4,435.84 | 15.46 | 64.10 | 4,515.40 | 811.12 | 21.9% |
| 200 | 45% | 65,700 | 5,038.96 | 5,156.35 | 23.19 | 74.59 | 5,254.13 | 215.17 | 4.3% |
| 200 | 60% | 87,600 | 5,901.16 | 5,876.86 | 30.92 | 85.07 | 5,992.85 | 91.69 | 1.6% |
| 200 | 75% | 109,500 | 6,763.37 | 6,597.37 | 38.65 | 95.56 | 6,731.58 | (31.79) | -0.5% |
| 500 | 15% | 54,750 | 5,730.10 | 7,324.13 | 19.33 | 105.75 | 7,449.21 | 1,719.11 | 30.0% |
| 500 | 30% | 109,500 | 8,803.67 | 11,038.57 | 38.65 | 159.51 | 11,236.73 | 2,433.06 | 27.6% |
| 500 | 45% | 164,250 | 10,959.17 | 12,839.85 | 57.98 | 185.73 | 13,083.56 | 2,124.39 | 19.4% |
| 500 | 60% | 219,000 | 13,114.68 | 14,641.12 | 77.31 | 211.95 | 14,930.38 | 1,815.70 | 13.8% |
| 500 | 75% | 273,750 | 15,270.19 | 16,442.40 | 96.63 | 238.16 | 16,777.19 | 1,507.00 | 9.9% |
| 1,500 | 15% | 164,250 | 17,064.32 | 17,843.10 | 57.98 | 257.78 | 18,158.86 | 1,094.54 | 6.4% |
| 1,500 | 30% | 328,500 | 24,226.70 | 28,986.43 | 115.96 | 419.07 | 29,521.46 | 5,294.76 | 21.9% |
| 1,500 | 45% | 492,750 | 30,693.22 | 34,390.26 | 173.94 | 497.72 | 35,061.92 | 4,368.70 | 14.2% |
| 1,500 | 60% | 657,000 | 37,159.74 | 39,794.08 | 231.92 | 576.37 | 40,602.37 | 3,442.63 | 9.3% |
| 1,500 | 75% | 821,250 | 43,626.26 | 45,197.91 | 289.90 | 655.02 | 46,142.83 | 2,516.57 | 5.8% |
| 3,000 | 15% | 328,500 | 34,065.65 | 34,733.41 | 115.96 | 501.83 | 35,351.20 | 1,285.55 | 3.8% |
| 3,000 | 30% | 657,000 | 47,361.24 | 57,020.08 | 231.92 | 824.43 | 58,076.43 | 10,715.19 | 22.6% |
| 3,000 | 45% | 985,500 | 60,294.29 | 67,827.73 | 347.88 | 981.73 | 69,157.34 | 8,863.05 | 14.7% |
| 3,000 | 60% | 1,314,000 | 73,227.33 | 78,635.38 | 463.84 | 1,139.03 | 80,238.25 | 7,010.92 | 9.6% |
| 3,000 | 75% | 1,642,500 | 86,160.38 | 89,443.03 | 579.80 | 1,296.33 | 91,319.16 | 5,158.78 | 6.0% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.
5) For purposes of calculating the monthly bill, E-32 customers are categorized in this manner:
   0 - 99 kW = self contained
   100 - 999 kW = Instrument-rated
   1000 and above = primary

**Arizona Public Service Company**

**Typical General Service Bill Analysis**
**E-32 Summer (May-October)**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Components of Proposed Bill | | | | Change | |
| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | | | (C) x $0.000353 | [(E) + (F)] x 0.0144 | (E) + (F) + (G) | (H) - (D) | (I) / (D) |
| 10 | 15% | 1,095 | 132.70 | 127.79 | 0.39 | 1.85 | 130.03 | (2.67) | -2.0% |
| 10 | 30% | 2,190 | 244.40 | 238.33 | 0.77 | 3.44 | 242.54 | (1.86) | -0.8% |
| 10 | 45% | 3,285 | 346.95 | 348.87 | 1.16 | 5.04 | 355.07 | 8.12 | 2.3% |
| 10 | 60% | 4,380 | 423.48 | 459.41 | 1.55 | 6.64 | 467.60 | 44.12 | 10.4% |
| 10 | 75% | 5,475 | 500.01 | 569.95 | 1.93 | 8.24 | 580.12 | 80.11 | 16.0% |
| 100 | 15% | 10,950 | 1,291.01 | 1,601.54 | 3.87 | 23.12 | 1,628.53 | 337.52 | 26.1% |
| 100 | 30% | 21,900 | 2,090.03 | 2,453.93 | 7.73 | 35.45 | 2,497.11 | 407.08 | 19.5% |
| 100 | 45% | 32,850 | 2,855.33 | 2,923.69 | 11.60 | 42.27 | 2,977.56 | 122.23 | 4.3% |
| 100 | 60% | 43,800 | 3,620.62 | 3,393.44 | 15.46 | 49.09 | 3,457.99 | (162.63) | -4.5% |
| 100 | 75% | 54,750 | 4,366.52 | 3,863.20 | 19.33 | 55.91 | 3,938.44 | (428.08) | -9.8% |
| 200 | 15% | 21,900 | 2,578.02 | 3,169.06 | 7.73 | 45.75 | 3,222.54 | 644.52 | 25.0% |
| 200 | 30% | 43,800 | 4,111.82 | 4,873.84 | 15.46 | 70.41 | 4,959.71 | 847.89 | 20.6% |
| 200 | 45% | 65,700 | 5,598.45 | 5,813.35 | 23.19 | 84.05 | 5,920.59 | 322.14 | 5.8% |
| 200 | 60% | 87,600 | 6,562.71 | 6,752.86 | 30.92 | 97.69 | 6,881.47 | 318.76 | 4.9% |
| 200 | 75% | 109,500 | 7,526.97 | 7,692.37 | 38.65 | 111.33 | 7,842.35 | 315.38 | 4.2% |
| 500 | 15% | 54,750 | 6,350.72 | 7,871.63 | 19.33 | 113.63 | 8,004.59 | 1,653.87 | 26.0% |
| 500 | 30% | 109,500 | 9,776.37 | 12,133.57 | 38.65 | 175.28 | 12,347.50 | 2,571.13 | 26.3% |
| 500 | 45% | 164,250 | 12,187.01 | 14,482.35 | 57.98 | 209.38 | 14,749.71 | 2,562.70 | 21.0% |
| 500 | 60% | 219,000 | 14,597.65 | 16,831.12 | 77.31 | 243.48 | 17,151.91 | 2,554.26 | 17.5% |
| 500 | 75% | 273,750 | 17,008.29 | 19,179.90 | 96.63 | 277.58 | 19,554.11 | 2,545.82 | 15.0% |
| 1,500 | 15% | 164,250 | 18,915.67 | 19,485.60 | 57.98 | 281.43 | 19,825.01 | 909.34 | 4.8% |
| 1,500 | 30% | 328,500 | 26,916.94 | 32,271.43 | 115.96 | 466.38 | 32,853.77 | 5,936.83 | 22.1% |
| 1,500 | 45% | 492,750 | 34,148.86 | 39,317.76 | 173.94 | 568.68 | 40,060.38 | 5,911.52 | 17.3% |
| 1,500 | 60% | 657,000 | 41,380.79 | 46,364.08 | 231.92 | 670.98 | 47,266.98 | 5,886.19 | 14.2% |
| 1,500 | 75% | 821,250 | 48,612.72 | 53,410.41 | 289.90 | 773.28 | 54,473.59 | 5,860.87 | 12.1% |
| 3,000 | 15% | 328,500 | 37,763.11 | 38,018.41 | 115.96 | 549.13 | 38,683.50 | 920.39 | 2.4% |
| 3,000 | 30% | 657,000 | 52,627.79 | 63,590.08 | 231.92 | 919.04 | 64,741.04 | 12,113.25 | 23.0% |
| 3,000 | 45% | 985,500 | 67,091.65 | 77,682.73 | 347.88 | 1,123.64 | 79,154.25 | 12,062.60 | 18.0% |
| 3,000 | 60% | 1,314,000 | 81,555.50 | 91,775.38 | 463.84 | 1,328.24 | 93,567.46 | 12,011.96 | 14.7% |
| 3,000 | 75% | 1,642,500 | 96,019.36 | 105,868.03 | 579.80 | 1,532.85 | 107,980.68 | 11,961.32 | 12.5% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.
5) For purposes of calculating the monthly bill, E-32 customers are categorized in this manner:
   *0 - 99 kW = self contained*
   100 - 999 kW = Instrument-rated

**Arizona Public Service Company**

**Typical General Service Bill Analysis**
**E-34**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Components of Proposed Bill | | | | Change | |
| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | | | (C) x $0.000353 | [(E) + (F)] x 0.0144 | (E) + (F) + (G) | (H) - (D) | (I) / (D) |
| 3,000 | 20% | 438,000 | 47,951.88 | 51,587.70 | 154.61 | 745.09 | 52,487.40 | 4,535.52 | 9.5% |
| 3,000 | 30% | 657,000 | 54,797.82 | 58,779.66 | 231.92 | 849.77 | 59,861.35 | 5,063.53 | 9.2% |
| 3,000 | 40% | 876,000 | 61,643.76 | 65,971.62 | 309.23 | 954.44 | 67,235.29 | 5,591.53 | 9.1% |
| 3,000 | 50% | 1,095,000 | 68,489.70 | 73,163.58 | 386.54 | 1,059.12 | 74,609.24 | 6,119.54 | 8.9% |
| 3,000 | 75% | 1,642,500 | 85,604.55 | 91,143.48 | 579.80 | 1,320.82 | 93,044.10 | 7,439.55 | 8.7% |
| 3,500 | 20% | 511,000 | 55,538.86 | 60,171.02 | 180.38 | 869.06 | 61,220.46 | 5,681.60 | 10.2% |
| 3,500 | 30% | 766,500 | 63,525.79 | 68,561.64 | 270.57 | 991.18 | 69,823.39 | 6,297.60 | 9.9% |
| 3,500 | 40% | 1,022,000 | 71,512.72 | 76,952.26 | 360.77 | 1,113.31 | 78,426.34 | 6,913.62 | 9.7% |
| 3,500 | 50% | 1,277,500 | 79,499.65 | 85,342.88 | 450.96 | 1,235.43 | 87,029.27 | 7,529.62 | 9.5% |
| 3,500 | 75% | 1,916,250 | 99,466.98 | 106,319.43 | 676.44 | 1,540.74 | 108,536.61 | 9,069.63 | 9.1% |
| 4,000 | 20% | 584,000 | 63,125.84 | 68,754.34 | 206.15 | 993.03 | 69,953.52 | 6,827.68 | 10.8% |
| 4,000 | 30% | 876,000 | 72,253.76 | 78,343.62 | 309.23 | 1,132.60 | 79,785.45 | 7,531.69 | 10.4% |
| 4,000 | 40% | 1,168,000 | 81,381.68 | 87,932.90 | 412.30 | 1,272.17 | 89,617.37 | 8,235.69 | 10.1% |
| 4,000 | 50% | 1,460,000 | 90,509.60 | 97,522.18 | 515.38 | 1,411.74 | 99,449.30 | 8,939.70 | 9.9% |
| 4,000 | 75% | 2,190,000 | 113,329.40 | 121,495.38 | 773.07 | 1,760.67 | 124,029.12 | 10,699.72 | 9.4% |
| 4,500 | 20% | 657,000 | 70,712.82 | 77,337.66 | 231.92 | 1,117.00 | 78,686.58 | 7,973.76 | 11.3% |
| 4,500 | 30% | 985,500 | 80,981.73 | 88,125.60 | 347.88 | 1,274.02 | 89,747.50 | 8,765.77 | 10.8% |
| 4,500 | 40% | 1,314,000 | 91,250.64 | 98,913.54 | 463.84 | 1,431.03 | 100,808.41 | 9,557.77 | 10.5% |
| 4,500 | 50% | 1,642,500 | 101,519.55 | 109,701.48 | 579.80 | 1,588.05 | 111,869.33 | 10,349.78 | 10.2% |
| 4,500 | 75% | 2,463,750 | 127,191.83 | 136,671.33 | 869.70 | 1,980.59 | 139,521.62 | 12,329.79 | 9.7% |
| 5,000 | 20% | 730,000 | 78,299.80 | 85,920.98 | 257.69 | 1,240.97 | 87,419.64 | 9,119.84 | 11.6% |
| 5,000 | 30% | 1,095,000 | 89,709.70 | 97,907.58 | 386.54 | 1,415.44 | 99,709.56 | 9,999.86 | 11.1% |
| 5,000 | 40% | 1,460,000 | 101,119.60 | 109,894.18 | 515.38 | 1,589.90 | 111,999.46 | 10,879.86 | 10.8% |
| 5,000 | 50% | 1,825,000 | 112,529.50 | 121,880.78 | 644.23 | 1,764.36 | 124,289.37 | 11,759.87 | 10.5% |
| 5,000 | 75% | 2,737,500 | 141,054.25 | 151,847.28 | 966.34 | 2,200.52 | 155,014.14 | 13,959.89 | 9.9% |
| 6,000 | 20% | 876,000 | 93,473.76 | 103,087.62 | 309.23 | 1,488.91 | 104,885.76 | 11,412.00 | 12.2% |
| 6,000 | 30% | 1,314,000 | 107,165.64 | 117,471.54 | 463.84 | 1,698.27 | 119,633.65 | 12,468.01 | 11.6% |
| 6,000 | 40% | 1,752,000 | 120,857.52 | 131,855.46 | 618.46 | 1,907.62 | 134,381.54 | 13,524.02 | 11.2% |
| 6,000 | 50% | 2,190,000 | 134,549.40 | 146,239.38 | 773.07 | 2,116.98 | 149,129.43 | 14,580.03 | 10.8% |
| 6,000 | 75% | 3,285,000 | 168,779.10 | 182,199.18 | 1,159.61 | 2,640.37 | 185,999.16 | 17,220.06 | 10.2% |
| 7,000 | 20% | 1,022,000 | 108,647.72 | 120,254.26 | 360.77 | 1,736.86 | 122,351.89 | 13,704.17 | 12.6% |
| 7,000 | 30% | 1,533,000 | 124,621.58 | 137,035.50 | 541.15 | 1,981.10 | 139,557.75 | 14,936.17 | 12.0% |
| 7,000 | 40% | 2,044,000 | 140,595.44 | 153,816.74 | 721.53 | 2,225.35 | 156,763.62 | 16,168.18 | 11.5% |
| 7,000 | 50% | 2,555,000 | 156,569.30 | 170,597.98 | 901.92 | 2,469.60 | 173,969.50 | 17,400.20 | 11.1% |
| 7,000 | 75% | 3,832,500 | 196,503.95 | 212,551.08 | 1,352.87 | 3,080.22 | 216,984.17 | 20,480.22 | 10.4% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.
5) For purposes of calculating the monthly bill, E-34 customers are categorized as primary customers.

**Arizona Public Service Company**

**Typical General Service Bill Analysis**
**E-35**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Components of Proposed Bill | | | | Change | |
| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill under Proposed Rates | Amount ($) | % |
| | | | | | (C) x $0.000353 | [(E) + (F)] x 0.0144 | (E) + (F) + (G) | (H) - (D) | (I) / (D) |
| 3,000 | 20% | 438,000 | 53,053.70 | 52,490.52 | 154.61 | 758.09 | 53,403.22 | 349.52 | 0.7% |
| 3,000 | 30% | 657,000 | 58,780.55 | 59,329.89 | 231.92 | 857.69 | 60,419.50 | 1,638.95 | 2.8% |
| 3,000 | 40% | 876,000 | 64,507.40 | 66,169.26 | 309.23 | 957.29 | 67,435.78 | 2,928.38 | 4.5% |
| 3,000 | 50% | 1,095,000 | 70,234.25 | 73,008.63 | 386.54 | 1,056.89 | 74,452.06 | 4,217.81 | 6.0% |
| 3,000 | 75% | 1,642,500 | 84,551.38 | 90,107.06 | 579.80 | 1,305.89 | 91,992.75 | 7,441.37 | 8.8% |
| 3,500 | 20% | 511,000 | 61,487.65 | 61,224.31 | 180.38 | 884.23 | 62,288.92 | 801.27 | 1.3% |
| 3,500 | 30% | 766,500 | 68,168.98 | 69,203.58 | 270.57 | 1,000.43 | 70,474.58 | 2,305.60 | 3.4% |
| 3,500 | 40% | 1,022,000 | 74,850.30 | 77,182.84 | 360.77 | 1,116.63 | 78,660.24 | 3,809.94 | 5.1% |
| 3,500 | 50% | 1,277,500 | 81,531.63 | 85,162.11 | 450.96 | 1,232.83 | 86,845.90 | 5,314.27 | 6.5% |
| 3,500 | 75% | 1,916,250 | 98,234.94 | 105,110.27 | 676.44 | 1,523.33 | 107,310.04 | 9,075.10 | 9.2% |
| 4,000 | 20% | 584,000 | 69,921.60 | 69,958.10 | 206.15 | 1,010.37 | 71,174.62 | 1,253.02 | 1.8% |
| 4,000 | 30% | 876,000 | 77,557.40 | 79,077.26 | 309.23 | 1,143.17 | 80,529.66 | 2,972.26 | 3.8% |
| 4,000 | 40% | 1,168,000 | 85,193.20 | 88,196.42 | 412.30 | 1,275.97 | 89,884.69 | 4,691.49 | 5.5% |
| 4,000 | 50% | 1,460,000 | 92,829.00 | 97,315.58 | 515.38 | 1,408.77 | 99,239.73 | 6,410.73 | 6.9% |
| 4,000 | 75% | 2,190,000 | 111,918.50 | 120,113.48 | 773.07 | 1,740.77 | 122,627.32 | 10,708.82 | 9.6% |
| 4,500 | 20% | 657,000 | 78,355.55 | 78,691.89 | 231.92 | 1,136.50 | 80,060.31 | 1,704.76 | 2.2% |
| 4,500 | 30% | 985,500 | 86,945.83 | 88,950.95 | 347.88 | 1,285.90 | 90,584.73 | 3,638.90 | 4.2% |
| 4,500 | 40% | 1,314,000 | 95,536.10 | 99,210.00 | 463.84 | 1,435.30 | 101,109.14 | 5,573.04 | 5.8% |
| 4,500 | 50% | 1,642,500 | 104,126.38 | 109,469.06 | 579.80 | 1,584.70 | 111,633.56 | 7,507.18 | 7.2% |
| 4,500 | 75% | 2,463,750 | 125,602.06 | 135,116.69 | 869.70 | 1,958.20 | 137,944.59 | 12,342.53 | 9.8% |
| 5,000 | 20% | 730,000 | 86,789.50 | 87,425.68 | 257.69 | 1,262.64 | 88,946.01 | 2,156.51 | 2.5% |
| 5,000 | 30% | 1,095,000 | 96,334.25 | 98,824.63 | 386.54 | 1,428.64 | 100,639.81 | 4,305.56 | 4.5% |
| 5,000 | 40% | 1,460,000 | 105,879.00 | 110,223.58 | 515.38 | 1,594.64 | 112,333.60 | 6,454.60 | 6.1% |
| 5,000 | 50% | 1,825,000 | 115,423.75 | 121,622.53 | 644.23 | 1,760.64 | 124,027.40 | 8,603.65 | 7.5% |
| 5,000 | 75% | 2,737,500 | 139,285.63 | 150,119.91 | 966.34 | 2,175.64 | 153,261.89 | 13,976.26 | 10.0% |
| 6,000 | 20% | 876,000 | 103,657.40 | 104,893.26 | 309.23 | 1,514.92 | 106,717.41 | 3,060.01 | 3.0% |
| 6,000 | 30% | 1,314,000 | 115,111.10 | 118,572.00 | 463.84 | 1,714.12 | 120,749.96 | 5,638.86 | 4.9% |
| 6,000 | 40% | 1,752,000 | 126,564.80 | 132,250.74 | 618.46 | 1,913.32 | 134,782.52 | 8,217.72 | 6.5% |
| 6,000 | 50% | 2,190,000 | 138,018.50 | 145,929.48 | 773.07 | 2,112.52 | 148,815.07 | 10,796.57 | 7.8% |
| 6,000 | 75% | 3,285,000 | 166,652.75 | 180,126.33 | 1,159.61 | 2,610.52 | 183,896.46 | 17,243.71 | 10.3% |
| 7,000 | 20% | 1,022,000 | 120,525.30 | 122,360.84 | 360.77 | 1,767.19 | 124,488.80 | 3,963.50 | 3.3% |
| 7,000 | 30% | 1,533,000 | 133,887.95 | 138,319.37 | 541.15 | 1,999.59 | 140,860.11 | 6,972.16 | 5.2% |
| 7,000 | 40% | 2,044,000 | 147,250.60 | 154,277.90 | 721.53 | 2,231.99 | 157,231.42 | 9,980.82 | 6.8% |
| 7,000 | 50% | 2,555,000 | 160,613.25 | 170,236.43 | 901.92 | 2,464.39 | 173,602.74 | 12,989.49 | 8.1% |
| 7,000 | 75% | 3,832,500 | 194,019.88 | 210,132.76 | 1,352.87 | 3,045.39 | 214,531.02 | 20,511.14 | 10.6% |

E-35 Average Energy On-Peak: 34%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.
5) For purposes of calculating the monthly bill, E-34 customers are categorized as primary customers.

**Arizona Public Service Company**

**Typical General Service Bill Analysis**
**E-221 Water Pumping Power**

**Customer Bills at Varying Consumption Levels**
**at Present and Proposed Rate Levels**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Components of Proposed Bill | | | | Change | |
| kW | Load Factor | kWh | Monthly Bill under Present Rates | Base | CRCC | Franchise | Monthly Bill Under Proposed Rates | Amount $ | % |
| | | | | | (C) x $0.000353 | [(E) + (F)] x 0.0144 | (E) + (F) + (G) | (H) - (D) | (I) / (D) |
| 10 | 20% | 1,460 | 132.52 | 136.15 | 0.52 | 1.97 | 138.63 | 6.11 | 4.6% |
| 10 | 35% | 2,555 | 203.05 | 211.83 | 0.90 | 3.06 | 215.79 | 12.74 | 6.3% |
| 10 | 50% | 3,650 | 265.97 | 275.36 | 1.29 | 3.98 | 280.63 | 14.66 | 5.5% |
| 10 | 65% | 4,745 | 323.89 | 336.26 | 1.67 | 4.87 | 342.81 | 18.92 | 5.8% |
| 10 | 80% | 5,840 | 381.80 | 397.17 | 2.06 | 5.75 | 404.98 | 23.17 | 6.1% |
| 30 | 20% | 4,380 | 353.00 | 373.95 | 1.55 | 5.41 | 380.91 | 27.91 | 7.9% |
| 30 | 35% | 7,665 | 564.58 | 600.98 | 2.71 | 8.69 | 612.38 | 47.79 | 8.5% |
| 30 | 50% | 10,950 | 747.83 | 791.58 | 3.87 | 11.45 | 806.90 | 59.07 | 7.9% |
| 30 | 65% | 14,235 | 921.58 | 974.29 | 5.02 | 14.10 | 993.42 | 71.84 | 7.8% |
| 30 | 80% | 17,520 | 1,095.32 | 1,157.00 | 6.18 | 16.75 | 1,179.94 | 84.62 | 7.7% |
| 75 | 20% | 10,950 | 849.07 | 909.00 | 3.87 | 13.15 | 926.02 | 76.94 | 9.1% |
| 75 | 35% | 19,163 | 1,378.07 | 1,476.60 | 6.76 | 21.36 | 1,504.73 | 126.66 | 9.2% |
| 75 | 50% | 27,375 | 1,832.01 | 1,953.08 | 9.66 | 28.26 | 1,991.01 | 159.00 | 8.7% |
| 75 | 65% | 35,588 | 2,266.40 | 2,409.89 | 12.56 | 34.88 | 2,457.33 | 190.94 | 8.4% |
| 75 | 80% | 43,800 | 2,700.73 | 2,866.64 | 15.46 | 41.50 | 2,923.60 | 222.87 | 8.3% |
| 100 | 20% | 14,600 | 1,124.67 | 1,206.26 | 5.15 | 17.44 | 1,228.85 | 104.19 | 9.3% |
| 100 | 35% | 25,550 | 1,829.96 | 1,963.01 | 9.02 | 28.40 | 2,000.43 | 170.47 | 9.3% |
| 100 | 50% | 36,500 | 2,434.33 | 2,598.36 | 12.88 | 37.60 | 2,648.84 | 214.51 | 8.8% |
| 100 | 65% | 47,450 | 3,013.48 | 3,207.39 | 16.75 | 46.43 | 3,270.57 | 257.09 | 8.5% |
| 100 | 80% | 58,400 | 3,592.62 | 3,816.43 | 20.62 | 55.25 | 3,892.30 | 299.68 | 8.3% |
| 150 | 20% | 21,900 | 1,675.86 | 1,800.76 | 7.73 | 26.04 | 1,834.53 | 158.67 | 9.5% |
| 150 | 35% | 38,325 | 2,733.79 | 2,935.89 | 13.53 | 42.47 | 2,991.89 | 258.10 | 9.4% |
| 150 | 50% | 54,750 | 3,638.97 | 3,888.91 | 19.33 | 56.28 | 3,964.51 | 325.54 | 8.9% |
| 150 | 65% | 71,175 | 4,507.69 | 4,802.47 | 25.12 | 69.52 | 4,897.11 | 389.42 | 8.6% |
| 150 | 80% | 87,600 | 5,376.41 | 5,716.02 | 30.92 | 82.76 | 5,829.70 | 453.29 | 8.4% |
| 200 | 20% | 29,200 | 2,227.05 | 2,395.26 | 10.31 | 34.64 | 2,440.21 | 213.16 | 9.6% |
| 200 | 35% | 51,100 | 3,637.63 | 3,908.77 | 18.04 | 56.55 | 3,983.36 | 345.72 | 9.5% |
| 200 | 50% | 73,000 | 4,843.62 | 5,179.46 | 25.77 | 74.96 | 5,280.18 | 436.57 | 9.0% |
| 200 | 65% | 94,900 | 6,001.91 | 6,397.54 | 33.50 | 92.61 | 6,523.64 | 521.74 | 8.7% |
| 200 | 80% | 116,800 | 7,160.20 | 7,615.62 | 41.23 | 110.26 | 7,767.10 | 606.91 | 8.5% |
| 300 | 20% | 43,800 | 3,329.44 | 3,584.27 | 15.46 | 51.84 | 3,651.57 | 322.13 | 9.7% |
| 300 | 35% | 76,650 | 5,445.31 | 5,854.53 | 27.06 | 84.69 | 5,966.28 | 520.98 | 9.6% |
| 300 | 50% | 109,500 | 7,252.90 | 7,760.57 | 38.65 | 112.31 | 7,911.53 | 658.63 | 9.1% |
| 300 | 65% | 142,350 | 8,990.34 | 9,587.68 | 50.25 | 138.79 | 9,776.72 | 786.38 | 8.7% |
| 300 | 80% | 175,200 | 10,727.77 | 11,414.80 | 61.85 | 165.26 | 11,641.91 | 914.13 | 8.5% |

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

H-5

## ARIZONA PUBLIC SERVICE COMPANY
## BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE
TEST YEAR ENDED DECEMBER 31, 2002 UNADJUSTED

RATE SCHEDULE: E-10
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

| | | SUMMER (May through October) | | | | | | WINTER (November through April) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | CUMULATIVE | | | | | | CUMULATIVE | | | | |
| | | | | BILLS | | CONSUMPTION | | | | BILLS | | CONSUMPTION | | |
| Line No. | BLOCK (kWh) | Number of BILLS BY BLOCK | CONSUMPTION kWh BY BLOCK | Number | % of Total | Amount (kWh) | % of Total | Number of BILLS BY BLOCK | CONSUMPTION kWh BY BLOCK | Number | % of Total | Amount (kWh) | % of Total | Line No. |
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | |
| 1 | 0 | 10,969 | - | 10,969 | 1.86% | - | 0.00% | 15,271 | - | 15,271 | 2.55% | - | 0.00% | 1 |
| 2 | 1-50 | 11,820 | 271,814 | 22,789 | 3.86% | 271,814 | 0.05% | 16,499 | 389,675 | 31,770 | 5.30% | 389,675 | 0.10% | 2 |
| 3 | 51-100 | 12,363 | 946,538 | 35,152 | 5.96% | 1,218,352 | 0.23% | 14,750 | 1,119,056 | 46,520 | 7.76% | 1,508,731 | 0.37% | 3 |
| 4 | 101-150 | 15,188 | 1,919,128 | 50,340 | 8.54% | 3,137,480 | 0.58% | 16,550 | 2,090,400 | 63,070 | 10.52% | 3,599,131 | 0.88% | 4 |
| 5 | 151-200 | 17,440 | 3,069,531 | 67,780 | 11.49% | 6,207,011 | 1.15% | 20,935 | 3,692,944 | 84,005 | 14.01% | 7,292,075 | 1.79% | 5 |
| 6 | 201-250 | 20,194 | 4,566,339 | 87,974 | 14.92% | 10,773,350 | 2.00% | 25,767 | 5,828,303 | 109,772 | 18.30% | 13,120,378 | 3.22% | 6 |
| 7 | 251-300 | 22,078 | 6,090,648 | 110,052 | 18.66% | 16,863,998 | 3.13% | 30,060 | 8,293,185 | 139,832 | 23.32% | 21,413,563 | 5.25% | 7 |
| 8 | 301-350 | 23,562 | 7,672,869 | 133,614 | 22.66% | 24,536,867 | 4.55% | 32,708 | 10,654,519 | 172,540 | 28.77% | 32,068,082 | 7.86% | 8 |
| 9 | 351-400 | 24,097 | 9,049,708 | 157,711 | 26.75% | 33,586,575 | 6.23% | 33,104 | 12,431,471 | 205,644 | 34.29% | 44,499,553 | 10.91% | 9 |
| 10 | 401-450 | 24,559 | 10,451,980 | 182,270 | 30.91% | 44,038,555 | 8.17% | 32,816 | 13,960,432 | 238,460 | 39.76% | 58,459,985 | 14.34% | 10 |
| 11 | 451-500 | 24,059 | 11,439,814 | 206,329 | 34.99% | 55,478,369 | 10.29% | 32,010 | 15,218,689 | 270,470 | 45.10% | 73,678,674 | 18.07% | 11 |
| 12 | 501-550 | 23,480 | 12,337,146 | 229,809 | 38.97% | 67,815,515 | 12.58% | 30,040 | 15,776,309 | 300,510 | 50.11% | 89,454,983 | 21.94% | 12 |
| 13 | 551-600 | 22,594 | 12,997,077 | 252,403 | 42.80% | 80,812,592 | 14.99% | 28,123 | 16,172,619 | 328,633 | 54.80% | 105,627,602 | 25.90% | 13 |
| 14 | 601-650 | 21,344 | 13,347,515 | 273,747 | 46.42% | 94,160,107 | 17.46% | 25,777 | 16,114,869 | 354,410 | 59.09% | 121,742,471 | 29.85% | 14 |
| 15 | 651-700 | 20,011 | 13,512,021 | 293,758 | 49.82% | 107,672,129 | 19.97% | 23,930 | 16,158,276 | 378,340 | 63.08% | 137,900,747 | 33.82% | 15 |
| 16 | 701-750 | 18,976 | 13,762,129 | 312,734 | 53.04% | 121,434,258 | 22.52% | 21,479 | 15,573,574 | 399,819 | 66.66% | 153,474,321 | 37.63% | 16 |
| 17 | 751-800 | 17,702 | 13,726,628 | 330,436 | 56.04% | 135,160,886 | 25.07% | 19,261 | 14,929,446 | 419,080 | 69.88% | 168,403,767 | 41.30% | 17 |
| 18 | 801-850 | 16,546 | 13,652,219 | 346,982 | 58.84% | 148,813,105 | 27.60% | 17,566 | 14,492,553 | 436,646 | 72.81% | 182,896,320 | 44.85% | 18 |
| 19 | 851-900 | 15,054 | 13,175,147 | 362,036 | 61.40% | 161,988,252 | 30.04% | 15,756 | 13,788,608 | 452,402 | 75.43% | 196,684,928 | 48.23% | 19 |
| 20 | 901-950 | 13,786 | 12,754,824 | 375,822 | 63.74% | 174,743,076 | 32.41% | 14,083 | 13,029,337 | 466,485 | 77.78% | 209,714,265 | 51.43% | 20 |
| 21 | 951-1,000 | 13,071 | 12,749,142 | 388,893 | 65.95% | 187,492,218 | 34.78% | 12,888 | 12,566,915 | 479,373 | 79.93% | 222,281,180 | 54.51% | 21 |
| 22 | 1,001-1,100 | 23,555 | 24,718,033 | 412,448 | 69.95% | 212,210,251 | 39.36% | 21,753 | 22,815,530 | 501,126 | 83.56% | 245,096,710 | 60.10% | 22 |
| 23 | 1,101-1,200 | 20,711 | 23,808,472 | 433,159 | 73.46% | 236,018,723 | 43.78% | 17,920 | 20,587,835 | 519,046 | 86.54% | 265,684,545 | 65.15% | 23 |
| 24 | 1,201-1,300 | 18,321 | 22,898,836 | 451,480 | 76.57% | 258,917,559 | 48.02% | 14,270 | 17,814,439 | 533,316 | 88.92% | 283,498,984 | 69.52% | 24 |
| 25 | 1,301-1,400 | 16,412 | 22,152,334 | 467,892 | 79.35% | 281,069,893 | 52.13% | 11,562 | 15,600,173 | 544,878 | 90.85% | 299,099,157 | 73.35% | 25 |
| 26 | 1,401-1,500 | 14,781 | 21,425,165 | 482,673 | 81.86% | 302,495,058 | 56.11% | 9,538 | 13,815,654 | 554,416 | 92.44% | 312,914,811 | 76.73% | 26 |
| 27 | 1,501-1,600 | 13,086 | 20,275,629 | 495,759 | 84.07% | 322,770,687 | 59.87% | 7,745 | 11,998,926 | 562,161 | 93.73% | 324,913,737 | 79.68% | 27 |
| 28 | 1,601-1,700 | 11,734 | 19,361,956 | 507,493 | 86.06% | 342,132,643 | 63.46% | 6,355 | 10,478,978 | 568,516 | 94.79% | 335,392,715 | 82.25% | 28 |
| 29 | 1,701-1,800 | 10,426 | 18,241,183 | 517,919 | 87.83% | 360,373,826 | 66.84% | 5,371 | 9,393,471 | 573,887 | 95.69% | 344,786,186 | 84.55% | 29 |
| 30 | 1,801-1,900 | 9,341 | 17,278,588 | 527,260 | 89.42% | 377,652,414 | 70.05% | 4,265 | 7,882,744 | 578,152 | 96.40% | 352,668,930 | 86.48% | 30 |
| 31 | 1,901-2,000 | 8,301 | 16,181,088 | 535,561 | 90.82% | 393,833,502 | 73.05% | 3,536 | 6,891,402 | 581,688 | 96.99% | 359,560,332 | 88.17% | 31 |
| 32 | 2,001-2,500 | 28,640 | 63,633,257 | 564,201 | 95.68% | 457,466,758 | 84.85% | 10,151 | 22,462,617 | 591,839 | 98.68% | 382,022,949 | 93.68% | 32 |
| 33 | 2,501-3,000 | 13,759 | 37,430,338 | 577,960 | 98.02% | 494,897,096 | 91.79% | 4,181 | 11,347,961 | 596,020 | 99.38% | 393,370,910 | 96.46% | 33 |
| 34 | 3,001-4,000 | 8,869 | 29,911,639 | 586,829 | 99.52% | 524,808,736 | 97.34% | 2,693 | 9,105,339 | 598,713 | 99.83% | 402,476,249 | 98.70% | 34 |
| 35 | 4,001-5,000 | 1,917 | 8,417,131 | 588,746 | 99.84% | 533,225,867 | 98.90% | 651 | 2,863,699 | 599,364 | 99.94% | 405,339,948 | 99.40% | 35 |
| 36 | 5,001-10,000 | 873 | 5,278,982 | 589,619 | 99.99% | 538,504,848 | 99.88% | 365 | 2,224,533 | 599,729 | 100.00% | 407,564,481 | 99.94% | 36 |
| 37 | 10,001-20,000 | 41 | 518,399 | 589,660 | 100.00% | 539,023,247 | 99.98% | 14 | 164,141 | 599,743 | 100.00% | 407,728,622 | 99.98% | 37 |
| 38 | over 20,000 | 3 | 130,967 | 589,663 | 100.00% | 539,154,214 | 100.00% | 1 | 68,240 | 599,744 | 100.00% | 407,796,862 | 100.00% | 38 |

| | | | | | |
|---|---|---|---|---|---|
| Average Number of Customers: | 98,277 | | Average Number of Customers: | 99,957 | |
| Average Consumption: | 914 | kWh per bill | Average Consumption: | 680 | kWh per bill |
| Median Consumption: | 703 | kWh per bill | Median Consumption: | 549 | kWh per bill |

Supporting Schedules:

Recap Schedules:

**ARIZONA PUBLIC SERVICE COMPANY**
**BILL COUNT**
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE
TEST YEAR ENDED DECEMBER 31, 2002 UNADJUSTED

RATE SCHEDULE: E-12
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

| | | SUMMER (May through October) | | | | | | WINTER (November through April) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | CUMULATIVE | | | | | | CUMULATIVE | | | | |
| | | | | BILLS | | CONSUMPTION | | | | BILLS | | CONSUMPTION | | |
| Line No. | BLOCK (kWh) | Number of BILLS BY BLOCK | CONSUMPTION kWh BY BLOCK | Number | % of Total | Amount (kWh) | % of Total | Number of BILLS BY BLOCK | CONSUMPTION kWh BY BLOCK | Number | % of Total | Amount (kWh) | % of Total | Line No. |
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | |
| 1 | 0 | 73,255 | - | 73,255 | 3.16% | - | 0.00% | 56,841 | - | 56,841 | 2.42% | - | 0.00% | 1 |
| 2 | 1-50 | 79,014 | 1,750,788 | 152,269 | 6.58% | 1,750,788 | 0.10% | 84,368 | 1,991,797 | 141,209 | 6.01% | 1,991,797 | 0.15% | 2 |
| 3 | 51-100 | 68,922 | 5,241,353 | 221,191 | 9.55% | 6,992,141 | 0.39% | 80,417 | 6,112,355 | 221,626 | 9.43% | 8,104,152 | 0.60% | 3 |
| 4 | 101-150 | 74,784 | 9,409,201 | 295,975 | 12.78% | 16,401,342 | 0.92% | 91,457 | 11,543,646 | 313,083 | 13.31% | 19,647,798 | 1.44% | 4 |
| 5 | 151-200 | 79,883 | 14,039,337 | 375,858 | 16.23% | 30,440,678 | 1.71% | 108,114 | 19,055,579 | 421,197 | 17.91% | 38,703,377 | 2.84% | 5 |
| 6 | 201-250 | 85,385 | 19,279,079 | 461,243 | 19.92% | 49,719,758 | 2.79% | 126,480 | 28,598,333 | 547,677 | 23.29% | 67,301,710 | 4.94% | 6 |
| 7 | 251-300 | 90,404 | 24,918,937 | 551,647 | 23.82% | 74,638,695 | 4.19% | 138,420 | 38,174,381 | 686,097 | 29.18% | 105,476,091 | 7.75% | 7 |
| 8 | 301-350 | 94,469 | 30,766,628 | 646,116 | 27.90% | 105,405,323 | 5.91% | 144,305 | 46,984,216 | 830,402 | 35.31% | 152,460,307 | 11.20% | 8 |
| 9 | 351-400 | 97,239 | 36,519,296 | 743,355 | 32.10% | 141,924,619 | 7.96% | 144,493 | 54,240,356 | 974,895 | 41.46% | 206,700,663 | 15.18% | 9 |
| 10 | 401-450 | 98,295 | 41,819,955 | 841,650 | 36.35% | 183,744,574 | 10.30% | 138,976 | 59,111,317 | 1,113,871 | 47.37% | 265,811,980 | 19.53% | 10 |
| 11 | 451-500 | 96,590 | 45,919,063 | 938,240 | 40.52% | 229,663,637 | 12.88% | 130,874 | 62,189,105 | 1,244,745 | 52.94% | 328,001,085 | 24.10% | 11 |
| 12 | 501-550 | 94,573 | 49,687,061 | 1,032,813 | 44.61% | 279,350,698 | 15.67% | 121,661 | 63,898,051 | 1,366,406 | 58.11% | 391,899,136 | 28.79% | 12 |
| 13 | 551-600 | 90,980 | 52,341,905 | 1,123,793 | 48.53% | 331,692,602 | 18.60% | 110,323 | 63,444,017 | 1,476,729 | 62.80% | 455,343,153 | 33.45% | 13 |
| 14 | 601-650 | 86,409 | 54,032,192 | 1,210,202 | 52.27% | 385,724,794 | 21.63% | 100,649 | 62,913,980 | 1,577,378 | 67.08% | 518,257,133 | 38.07% | 14 |
| 15 | 651-700 | 82,005 | 55,373,048 | 1,292,207 | 55.81% | 441,097,843 | 24.74% | 89,351 | 60,320,476 | 1,666,729 | 70.88% | 578,577,609 | 42.50% | 15 |
| 16 | 701-750 | 77,061 | 55,886,951 | 1,369,268 | 59.14% | 496,984,794 | 27.87% | 79,821 | 57,872,752 | 1,746,550 | 74.28% | 636,450,361 | 46.76% | 16 |
| 17 | 751-800 | 72,384 | 56,113,330 | 1,441,652 | 62.26% | 553,098,124 | 31.02% | 70,389 | 54,555,609 | 1,816,939 | 77.27% | 691,005,970 | 50.76% | 17 |
| 18 | 801-850 | 67,376 | 55,603,404 | 1,509,028 | 65.17% | 608,701,527 | 34.14% | 62,461 | 51,524,982 | 1,879,400 | 79.93% | 742,530,952 | 54.55% | 18 |
| 19 | 851-900 | 62,081 | 54,328,374 | 1,571,109 | 67.85% | 663,029,901 | 37.18% | 54,890 | 48,030,183 | 1,934,290 | 82.26% | 790,561,135 | 58.08% | 19 |
| 20 | 901-950 | 57,874 | 53,545,371 | 1,628,983 | 70.35% | 716,575,273 | 40.19% | 47,678 | 44,103,327 | 1,981,968 | 84.29% | 834,664,462 | 61.32% | 20 |
| 21 | 951-1,000 | 54,357 | 53,008,068 | 1,683,340 | 72.70% | 769,583,340 | 43.16% | 42,480 | 41,413,573 | 2,024,448 | 86.09% | 876,078,035 | 64.36% | 21 |
| 22 | 1,001-1,100 | 96,393 | 101,139,761 | 1,779,733 | 76.86% | 870,723,101 | 48.83% | 69,998 | 73,373,236 | 2,094,446 | 89.07% | 949,451,271 | 69.75% | 22 |
| 23 | 1,101-1,200 | 82,575 | 94,895,161 | 1,862,308 | 80.43% | 965,618,262 | 54.15% | 53,677 | 61,642,109 | 2,148,123 | 91.35% | 1,011,093,380 | 74.28% | 23 |
| 24 | 1,201-1,300 | 70,924 | 88,592,265 | 1,933,232 | 83.49% | 1,054,210,527 | 59.12% | 41,485 | 51,784,646 | 2,189,608 | 93.12% | 1,062,878,026 | 78.08% | 24 |
| 25 | 1,301-1,400 | 60,670 | 81,850,704 | 1,993,902 | 86.11% | 1,136,061,231 | 63.71% | 32,199 | 43,424,711 | 2,221,807 | 94.49% | 1,106,302,737 | 81.27% | 25 |
| 26 | 1,401-1,500 | 51,004 | 73,910,912 | 2,044,906 | 88.32% | 1,209,972,143 | 67.86% | 25,160 | 36,436,848 | 2,246,967 | 95.56% | 1,142,739,585 | 83.95% | 26 |
| 27 | 1,501-1,600 | 43,276 | 67,037,640 | 2,088,182 | 90.18% | 1,277,009,783 | 71.62% | 19,577 | 30,309,086 | 2,266,544 | 96.39% | 1,173,048,671 | 86.18% | 27 |
| 28 | 1,601-1,700 | 36,690 | 60,505,916 | 2,124,872 | 91.77% | 1,337,515,699 | 75.01% | 15,475 | 25,509,621 | 2,282,019 | 97.05% | 1,198,558,292 | 88.05% | 28 |
| 29 | 1,701-1,800 | 30,743 | 53,767,959 | 2,155,615 | 93.10% | 1,391,283,658 | 78.03% | 12,336 | 21,575,341 | 2,294,355 | 97.57% | 1,220,133,633 | 89.63% | 29 |
| 30 | 1,801-1,900 | 25,969 | 48,016,286 | 2,181,584 | 94.22% | 1,439,299,944 | 80.72% | 9,861 | 18,229,373 | 2,304,216 | 97.99% | 1,238,363,006 | 90.97% | 30 |
| 31 | 1,901-2,000 | 21,529 | 41,953,193 | 2,203,113 | 95.15% | 1,481,253,136 | 83.07% | 8,055 | 15,693,907 | 2,312,271 | 98.33% | 1,254,056,913 | 92.13% | 31 |
| 32 | 2,001-2,500 | 64,190 | 142,121,632 | 2,267,303 | 97.92% | 1,623,374,768 | 91.04% | 21,902 | 48,424,413 | 2,334,173 | 99.27% | 1,302,481,326 | 95.68% | 32 |
| 33 | 2,501-3,000 | 25,915 | 70,282,940 | 2,293,218 | 99.04% | 1,693,657,708 | 94.98% | 8,848 | 24,026,027 | 2,343,021 | 99.64% | 1,326,507,353 | 97.45% | 33 |
| 34 | 3,001-4,000 | 15,737 | 53,120,484 | 2,308,955 | 99.72% | 1,746,778,192 | 97.96% | 5,779 | 19,496,998 | 2,348,800 | 99.89% | 1,346,004,351 | 98.88% | 34 |
| 35 | 4,001-5,000 | 3,786 | 16,634,949 | 2,312,741 | 99.88% | 1,763,413,141 | 98.90% | 1,481 | 6,538,043 | 2,350,281 | 99.95% | 1,352,542,394 | 99.36% | 35 |
| 36 | 5,001-10,000 | 2,451 | 15,443,309 | 2,315,192 | 99.99% | 1,778,856,450 | 99.76% | 1,030 | 6,460,052 | 2,351,311 | 100.00% | 1,359,002,446 | 99.84% | 36 |
| 37 | 10,001-20,000 | 246 | 3,139,151 | 2,315,438 | 100.00% | 1,781,995,601 | 99.94% | 96 | 1,187,240 | 2,351,407 | 100.00% | 1,360,189,686 | 99.92% | 37 |
| 38 | over 20,000 | 20 | 1,103,723 | 2,315,458 | 100.00% | 1,783,099,324 | 100.00% | 20 | 1,042,692 | 2,351,427 | 100.00% | 1,361,232,378 | 100.00% | 38 |

| | | |
|---|---|---|
| Average Number of Customers: | 385,910 | |
| Average Consumption: | 770 | kWh per bill |
| Median Consumption: | 620 | kWh per bill |

| | | |
|---|---|---|
| Average Number of Customers: | 391,905 | |
| Average Consumption: | 579 | kWh per bill |
| Median Consumption: | 474 | kWh per bill |

Supporting Schedules:

Recap Schedules:

**ARIZONA PUBLIC SERVICE COMPANY**
**BILL COUNT**
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE
TEST YEAR ENDED DECEMBER 31, 2002 UNADJUSTED

RATE SCHEDULE: ET-1
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

| | | SUMMER (May through October) | | | | | | WINTER (November through April) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | CUMULATIVE | | | | | | CUMULATIVE | | | | |
| | | | | BILLS | | CONSUMPTION | | | | BILLS | | CONSUMPTION | | |
| Line No. | BLOCK (kWh) | Number of BILLS BY BLOCK | CONSUMPTION kWh BY BLOCK | Number | % of Total | Amount (kWh) | % of Total | Number of BILLS BY BLOCK | CONSUMPTION kWh BY BLOCK | Number | % of Total | Amount (kWh) | % of Total | Line No. |
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | |
| 1 | 0 | 7,585 | - | 7,585 | 0.46% | - | 0.00% | 6,809 | - | 6,809 | 0.42% | - | 0.00% | 1 |
| 2 | 1-50 | 7,637 | 178,525 | 15,222 | 0.92% | 178,525 | 0.01% | 9,586 | 232,695 | 16,395 | 1.00% | 232,695 | 0.01% | 2 |
| 3 | 51-100 | 6,530 | 496,872 | 21,752 | 1.31% | 675,396 | 0.02% | 10,102 | 773,257 | 26,497 | 1.62% | 1,005,952 | 0.06% | 3 |
| 4 | 101-150 | 7,273 | 914,168 | 29,025 | 1.75% | 1,589,564 | 0.06% | 11,590 | 1,464,008 | 38,087 | 2.33% | 2,469,960 | 0.14% | 4 |
| 5 | 151-200 | 7,677 | 1,347,547 | 36,702 | 2.22% | 2,937,111 | 0.10% | 14,925 | 2,638,932 | 53,012 | 3.25% | 5,108,892 | 0.30% | 5 |
| 6 | 201-250 | 8,573 | 1,938,217 | 45,275 | 2.73% | 4,875,328 | 0.17% | 21,742 | 4,938,596 | 74,754 | 4.58% | 10,047,488 | 0.59% | 6 |
| 7 | 251-300 | 9,621 | 2,656,523 | 54,896 | 3.31% | 7,531,851 | 0.26% | 30,365 | 8,403,076 | 105,119 | 6.44% | 18,450,564 | 1.07% | 7 |
| 8 | 301-350 | 11,580 | 3,777,063 | 66,476 | 4.01% | 11,308,914 | 0.39% | 39,221 | 12,806,793 | 144,340 | 8.85% | 31,257,357 | 1.82% | 8 |
| 9 | 351-400 | 13,484 | 5,072,267 | 79,960 | 4.83% | 16,381,181 | 0.57% | 47,483 | 17,858,413 | 191,823 | 11.76% | 49,115,770 | 2.86% | 9 |
| 10 | 401-450 | 15,605 | 6,649,451 | 95,565 | 5.77% | 23,030,632 | 0.80% | 53,497 | 22,787,979 | 245,320 | 15.03% | 71,903,749 | 4.19% | 10 |
| 11 | 451-500 | 18,059 | 8,600,082 | 113,624 | 6.86% | 31,630,714 | 1.10% | 57,333 | 27,276,914 | 302,653 | 18.55% | 99,180,663 | 5.78% | 11 |
| 12 | 501-550 | 20,447 | 10,753,822 | 134,071 | 8.09% | 42,384,536 | 1.47% | 60,313 | 31,702,420 | 362,966 | 22.24% | 130,883,083 | 7.62% | 12 |
| 13 | 551-600 | 22,808 | 13,135,174 | 156,879 | 9.47% | 55,519,710 | 1.93% | 62,320 | 35,874,982 | 425,286 | 26.06% | 166,758,065 | 9.71% | 13 |
| 14 | 601-650 | 24,831 | 15,536,782 | 181,710 | 10.97% | 71,056,492 | 2.47% | 62,561 | 39,134,244 | 487,847 | 29.90% | 205,892,309 | 11.99% | 14 |
| 15 | 651-700 | 26,390 | 17,834,100 | 208,100 | 12.56% | 88,890,592 | 3.09% | 63,388 | 42,816,076 | 551,235 | 33.78% | 248,708,385 | 14.49% | 15 |
| 16 | 701-750 | 28,290 | 20,532,086 | 236,390 | 14.27% | 109,422,677 | 3.80% | 62,654 | 45,452,135 | 613,889 | 37.62% | 294,160,520 | 17.13% | 16 |
| 17 | 751-800 | 29,705 | 23,043,368 | 266,095 | 16.06% | 132,466,045 | 4.60% | 61,596 | 47,762,998 | 675,485 | 41.39% | 341,923,518 | 19.91% | 17 |
| 18 | 801-850 | 31,347 | 25,883,627 | 297,442 | 17.96% | 158,349,672 | 5.50% | 59,829 | 49,384,474 | 735,314 | 45.06% | 391,307,992 | 22.79% | 18 |
| 19 | 851-900 | 33,007 | 28,907,105 | 330,449 | 19.95% | 187,256,777 | 6.51% | 58,504 | 51,215,473 | 793,818 | 48.65% | 442,523,465 | 25.77% | 19 |
| 20 | 901-950 | 33,903 | 31,382,276 | 364,352 | 22.00% | 218,639,053 | 7.60% | 56,767 | 52,526,255 | 850,585 | 52.12% | 495,049,720 | 28.83% | 20 |
| 21 | 951-1,000 | 34,914 | 34,063,038 | 399,266 | 24.10% | 252,702,091 | 8.78% | 54,757 | 53,409,876 | 905,342 | 55.48% | 548,459,596 | 31.94% | 21 |
| 22 | 1,001-1,100 | 71,598 | 75,234,924 | 470,864 | 28.43% | 327,937,015 | 11.40% | 102,311 | 107,386,373 | 1,007,653 | 61.75% | 655,845,969 | 38.20% | 22 |
| 23 | 1,101-1,200 | 74,220 | 85,404,894 | 545,084 | 32.91% | 413,341,909 | 14.37% | 91,647 | 105,343,791 | 1,099,300 | 67.37% | 761,189,760 | 44.33% | 23 |
| 24 | 1,201-1,300 | 75,517 | 94,442,128 | 620,601 | 37.47% | 507,784,037 | 17.65% | 81,432 | 101,747,026 | 1,180,732 | 72.36% | 862,936,786 | 50.26% | 24 |
| 25 | 1,301-1,400 | 75,492 | 101,939,961 | 696,093 | 42.02% | 609,723,998 | 21.19% | 70,020 | 94,467,817 | 1,250,752 | 76.65% | 957,404,603 | 55.76% | 25 |
| 26 | 1,401-1,500 | 74,815 | 108,518,372 | 770,908 | 46.54% | 718,242,370 | 24.96% | 60,837 | 88,168,811 | 1,311,589 | 80.38% | 1,045,573,414 | 60.90% | 26 |
| 27 | 1,501-1,600 | 73,567 | 114,045,355 | 844,475 | 50.98% | 832,287,725 | 28.93% | 52,001 | 80,557,523 | 1,363,590 | 83.56% | 1,126,130,937 | 65.59% | 27 |
| 28 | 1,601-1,700 | 70,881 | 116,967,797 | 915,356 | 55.26% | 949,255,522 | 32.99% | 43,919 | 72,438,414 | 1,407,509 | 86.25% | 1,198,569,351 | 69.81% | 28 |
| 29 | 1,701-1,800 | 67,851 | 118,757,552 | 983,207 | 59.36% | 1,068,013,074 | 37.12% | 36,741 | 64,267,700 | 1,444,250 | 88.51% | 1,262,837,051 | 73.55% | 29 |
| 30 | 1,801-1,900 | 64,357 | 119,047,122 | 1,047,564 | 63.24% | 1,187,060,196 | 41.26% | 31,136 | 57,571,994 | 1,475,386 | 90.41% | 1,320,409,045 | 76.90% | 30 |
| 31 | 1,901-2,000 | 59,820 | 116,644,620 | 1,107,384 | 66.85% | 1,303,704,816 | 45.31% | 25,989 | 50,653,402 | 1,501,375 | 92.01% | 1,371,062,447 | 79.85% | 31 |
| 32 | 2,001-2,500 | 237,157 | 529,392,783 | 1,344,541 | 81.17% | 1,833,097,599 | 63.71% | 76,636 | 169,580,354 | 1,578,011 | 96.70% | 1,540,642,801 | 89.73% | 32 |
| 33 | 2,501-3,000 | 144,889 | 395,145,141 | 1,489,430 | 89.92% | 2,228,242,740 | 77.44% | 29,752 | 80,678,618 | 1,607,763 | 98.53% | 1,621,321,419 | 94.43% | 33 |
| 34 | 3,001-4,000 | 119,935 | 406,972,350 | 1,609,365 | 97.16% | 2,635,215,090 | 91.58% | 17,400 | 58,642,270 | 1,625,163 | 99.59% | 1,679,963,689 | 97.84% | 34 |
| 35 | 4,001-5,000 | 31,466 | 138,185,012 | 1,640,831 | 99.06% | 2,773,400,102 | 96.39% | 4,023 | 17,691,875 | 1,629,186 | 99.84% | 1,697,655,564 | 98.87% | 35 |
| 36 | 5,001-10,000 | 14,691 | 89,262,056 | 1,655,522 | 99.94% | 2,862,662,158 | 99.49% | 2,401 | 15,023,128 | 1,631,587 | 99.99% | 1,712,678,692 | 99.75% | 36 |
| 37 | 10,001-20,000 | 794 | 10,052,066 | 1,656,316 | 99.99% | 2,872,714,223 | 99.84% | 183 | 2,392,108 | 1,631,770 | 100.00% | 1,715,070,800 | 99.89% | 37 |
| 38 | over 20,000 | 142 | 4,637,271 | 1,656,458 | 100.00% | 2,877,351,495 | 100.00% | 50 | 1,930,644 | 1,631,820 | 100.00% | 1,717,001,444 | 100.00% | 38 |

| | | | | | |
|---|---|---|---|---|---|
| Average Number of Customers: | 276,076 | | Average Number of Customers: | 271,970 | |
| Average Consumption: | 1,737 | kWh per bill | Average Consumption: | 1,052 | kWh per bill |
| Median Consumption: | 1,578 | kWh per bill | Median Consumption: | 920 | kWh per bill |

Supporting Schedules:

Recap Schedules:

# Index

# ARIZONA PUBLIC SERVICE COMPANY

Index to Rate and Service Schedules

## CLASSIFICATION OF SERVICES

Classification of Services

## RESIDENTIAL

| | |
|---|---|
| E-3 | Energy Support Program |
| E-4 | Medical Care Equipment |
| E-10 | Classic Rate - FROZEN |
| E-12 | Standard Rate |
| ECT-1R | Time-Of-Use with Demand Charge – Combined Advantage Plan |
| ET-1 | Time-Of-Use – Time Advantage Plan |

## GENERAL SERVICE

| | |
|---|---|
| E-30 | Extra Small Unmetered |
| E-32 | General Service |
| E-32R | Partial Requirements |
| E-32TOU | Time-Of-Use |
| E-34 | Extra Large General Service |
| E-35 | Extra Large General Service Time-Of-Use |
| E-53 | Athletic Stadiums & Sports Fields |
| E-54 | Seasonal Service |

## CLASSIFIED

| | |
|---|---|
| E-20 | Time-Of-Use for Religious Houses of Worship - FROZEN |
| E-36 | Station Use Service |
| E-40 | Agricultural Wind Machine Service |
| E-47 | Dusk to Dawn Lighting Service - PARTIALLY FROZEN |
| E-51 | Optional Electric Service for Qualified Cogeneration and Small Power Production Facilities Over 100 kW - FROZEN |
| E-52 | Electric Service for Partial Requirements Service of Less than 3,000 kW |
| E-55 | Electric Service for Partial Requirements Service 3,000 kW or Greater |
| E-58 | Street Lighting Service - PARTIALLY FROZEN |
| E-59 | Government Owned Street Lighting Systems |
| E-66 | Share the Light - Litchfield Park Street Lighting - FROZEN |
| E-67 | Municipal Lighting Service - City of Phoenix |
| E-114 | Share the Light - Lower Miami & Claypool Lighting Service - FROZEN |
| E-116 | Share the Light - Central Heights & Country Club Manor Street Lighting - FROZEN |
| E-145 | Share the Light - Ajo Heights Street Lighting - FROZEN |
| E-221 | Water Pumping Service |
| E-221-8T | Water Pumping Time-of-Use |
| E-249 | Share the Light - Camp Verde Street Lighting - FROZEN |

# ARIZONA PUBLIC SERVICE COMPANY

Index to Rate and Service Schedules

**CLASSIFIED** (cont'd)


| | |
|---|---|
| EPR-2 | Purchase Rates for Qualified Facilities Under 100 kW for Partial Requirements |
| EPR-3 | Purchase Rates for Qualified Facilities 10 kW or Less for Partial Requirements - FROZEN |
| EPR-4 | Purchase Rates for Renewable Qualified Facilities 10 kW or Less for Partial Requirements |
| EQF-M | Scheduled Maintenance Service for Qualified Facilities |
| EQF-S | Standby Electric Service for Qualified Facilities |
| Solar-1 | Photovoltaic Service Pilot Program - FROZEN |
| Solar-2 | Individual Solar Electric Service |
| SP-1 | Solar Partners |


**ADJUSTMENTS**


| | |
|---|---|
| CRCC-1 | Competition Rules Compliance Charge |
| EPS-1 | Environmental Portfolio Surcharge |
| PSA-1 | Power Supply Adjustment |
| RCDAC-1 | Returning Customer Adjustment |
| SBAC-1 | System Benefit Adjustment Charge |
| TCA-1 | Transmission Cost Adjustment |


**SERVICE SCHEDULES**


| | |
|---|---|
| Schedule 1 | Terms and Conditions for Standard Offer and Direct Access |
| Schedule 2 | Terms and Conditions for Energy Purchases from Qualified Cogeneration and Small Power Production Facilities |
| Schedule 3 | Conditions Governing Extensions of Electric Distribution Lines and Services |
| Schedule 4 | Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service |
| Schedule 5 | Guidelines for Electric Curtailment |
| Schedule 7 | Electric Meter Testing and Maintenance Plan |
| Schedule 10 | Terms and Conditions for Direct Access |
| Schedule 15 | Conditions Governing the Providing of Specialized Metering |

# Classification of Services

A. RESIDENTIAL SERVICE

1. Residence - Single

Residential service to a single residence covers electric service to a private residence or individually metered apartment unit, only.

Outbuildings on the same premises may be connected to the residential service meter, but only if such outbuildings form a part of the general living establishment.

2. Residence - Multiple

Residential service to two or more residences on the same premises or a residence or residences subdivided into two or more individual housekeeping apartments shall not be supplied through one meter on a Residential Service Rate Schedule.

Individual meters will be installed by the Company for each individual dwelling or housekeeping unit. If, for any reason, a separate meter is not installed for each individual dwelling or housekeeping unit, then the appropriate General Service Rate Schedule will be used for billing for the service supplied through the single meter.

3. Professional Offices or Commercial Activities in Dwellings

The supply of service under a Residential Rate Schedule to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the energy used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters.

Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electric equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises shall be classified as non-residential and the appropriate General Service Rate Schedule shall be applied. Customer may at his option provide separate circuits so that the residential uses can be metered and billed separately under the appropriate Residential Service Rate Schedule, and the other uses under the appropriate General Service Rate Schedule.

4. Farm and Rural Residences

The Residential Service Rate Schedules are available for electric service through one meter to a farm residence, and the usual farm uses outside the dwelling unit, but not if the use extends to operations such as canning plants, packing plants, stone quarries, ice cream manufacturing plants, stores, restaurants, tea rooms, tourist and trailer camps, gasoline stations, automobile service stations, repair shops, blacksmith shops or any other commercial or non-farming operation.

In no case shall the use extend to the processing, preparing or distributing of products not raised on the same farm and in no cases shall the use extend to a hatchery, dairy, butchery, greenhouse, or any other specialized operation unless such operation is conducted solely by the farmer and is incidental to the usual farm residence uses.

Customer may at his option elect to take the entire service under the appropriate General Service Rate Schedule, or may provide separate circuits so that the residential uses, together with the usual farm uses outside the dwelling unit, can be metered and billed separately under the appropriate Residential Service Rate Schedule, and the other uses under the appropriate General Service Rate Schedule.

The Residential Service Rate Schedules are not available for any use outside the dwelling unit on a farm which is not operated by an individual owner or lessee, occupying the farm residence.

B. GENERAL SERVICE

This covers service to any establishment for any purpose not prohibited by the rate schedule or Agreement for Service.

The General Service Rate Schedules are available only when all electric service required on the premises is taken through one meter at one point of delivery, except that:

(a) General Service Rate Schedules are available for more than one point of delivery on any one premise, provided that in such event, service supplied at each point of delivery will be separately metered and separately billed.

(b) The General Service Rate Schedules will be available for service to that portion of the Customer's premises which cannot be served at the Residential Service Rate Schedule or a Classified Service Rate Schedule. Service to such portion of the premises shall be considered as service to a separate customer, and all electric service taken therein at the General Service Rate Schedule must be through one meter at one point of delivery.

C. CLASSIFIED SERVICE

Classified service covers service for which specific rate schedules are available, due to the nature and load characteristics of the particular business. For such service, the General Service Rate Schedule may be used, except as specifically prohibited in that Schedule, while Classified Rate Schedules are available only to those businesses complying with the specific requirements of the particular schedule.

Service supplied under a Classified Rate Schedule shall be used only for the purposes specified in such rate schedule. In the event the Company questions whether the service is being used in compliance with said rate schedule, the customer shall have the burden of establishing such compliance to the satisfaction of the Company. In the absence of such compliance, the Company may substitute an appropriate General Service Rate Schedule.

A customer conducting mixed operations, a part of which may be served at a Classified Rate Schedule may, at his option, elect to take the entire service under the General Service Rate Schedule or may provide separate circuits so that the classified service can be metered and billed separately at the available classified schedule, and the other uses metered and billed under the available General Service Rate Schedule.

The Classified Services for which specific rate schedules are available, excluding special street light service, are listed below.

| Schedule No. | Classification |
|---|---|
| E-20* | Time of Use for Religious Houses of Worship |
| E-36 | Station Use Service |
| E-40 | Agricultural Wind Machine Service |
| E-47** | Dusk to Dawn Lighting Service |
| E-51* | Optional Electric Service for Qualified Cogeneration and Small Power Production Facilities over 100 kW |
| E-52 | Electric Service for Partial Requirements Service of less than 3,000 kW |
| E-55 | Electric Service for Partial Requirements Service 3,000 kW or greater |
| E-58** | Street Lighting Service |
| E-59 | Government Owned Street Lighting Systems |
| E-221 | Water Pumping Service |
| E-221-8T | Water Pumping Service Time of Use |
| EQF-M | Scheduled Maintenance Service for Qualified Facilities |
| EQF-S | Standby Electric Service for Qualified Facilities |
| Solar-1* | Photovoltaic Service Pilot Program |
| Solar-2 | Individual Solar Electric Service |
| SP-1 | Solar Partners |
| | Purchase Rates |
| EPR-2 | Purchase Rates for Qualified Facilities under 100 kW for Partial Requirements |
| EPR-3* | Purchase Rates for Qualified Facilities 10 kW or Less for Partial Requirements |
| EPR-4 | Purchase Rates for Renewable Qualified Facilities 10 kW or Less for Partial Requirements |

* Frozen Rate
** Partially Frozen Rate

Residential

# RATE SCHEDULE E-3
# RESIDENTIAL SERVICE
# ENERGY SUPPORT PROGRAM

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Residential Energy Support Program pursuant to Arizona Corporation Commission Decision No. 55931 and 56680. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

## RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

| For Bills with Usage of: | | The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by: |
|---|---|---|
| 0 – 400 | kWh | 30% |
| 401 – 800 | kWh | 20% |
| 801 – 1200 | kWh | 10% |
| 1201 | kWh and above | $10.00 |

# RATE SCHEDULE E-4
# RESIDENTIAL SERVICE
# MEDICAL CARE EQUIPMENT

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Medical Care Equipment Program pursuant to Arizona Corporation Commission Decision No. 59222. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

## RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

| For Bills with Usage of: | The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessment and Franchise Fees) Will be Discounted by: |
|---|---|
| 0 – 800 kWh | 30% |
| 801 – 1400 kWh | 20% |
| 1401 – 2000 kWh | 10% |
| 2001 kWh and above | $20.00 |

# RATE SCHEDULE E-10
# RESIDENTIAL SERVICE
# CLASSIC RATE

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes. Direct Access customers are not eligible for service under this schedule.

Additionally, this rate schedule is applicable only to those customers being served on the Company's Rate Schedule E-10 prior to December 6, 1991. This rate schedule will terminate twelve (12) months after the effective date shown below. At that time, customers will be transferred to other applicable residential schedules.

This rate schedule is not applicable to breakdown, standby, supplementary or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

## RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.271 per day; plus

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $0.07332 per kWh for the first 400 kWh, plus<br>$0.10083 per kWh for the next 400 kWh, plus<br>$0.10358 per kWh for all additional kWh | $0.08349 per kWh |

FROZEN

RATES (cont)

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

PROPOSED

# RATE SCHEDULE E-12
# RESIDENTIAL SERVICE
# STANDARD RATE

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes. Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplementary or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

## RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.411 per day; plus

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $0.08640 per kWh for the first 800 kWh, plus<br>$0.11006 per kWh for all additional kWh | $0.07004 per kWh |

The Bundled Standard Offer Service rate consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $0.215 per day

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:

| | | |
|---|---|---|
| Metering | $0.079 | per day |
| Meter Reading | $0.055 | per day |
| Billing | $0.062 | per day |

System Benefits Charge: $0.00161 per kWh

Transmission Charge: $0.00476 per kWh

Distribution Charge: $0.02181 per kWh

Generation Charges:

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $0.05822 per kWh for the first 800 kWh, plus $0.08188 per kWh for all additional kWh | $0.04186 per kWh |

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, charges will be applied to the customer's bill in accordance with this rate schedule.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplementary or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

## RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

### Bundled Standard Offer Service

Basic Service Charge: $0.493 per day; plus

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $11.00 per kW during On-Peak hours, plus<br>$ 0.05204 per kWh during On-Peak hours, plus<br>$ 0.03202 per kWh during Off-Peak hours | $8.00 per kW, plus<br>$0.03025 per kWh |

The Bundled Standard Offer Service Rate consists of the following Unbundled Components:

### Unbundled Components

Basic Service Charge: $0.211 per day

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:

| | | |
|---|---|---|
| Metering | $0.165 | per day |
| Meter Reading | $0.055 | per day |
| Billing | $0.062 | per day |

| | | |
|---|---|---|
| System Benefits Charge: | $0.00161 | per kWh |
| Transmission Charge: | $0.00476 | per kWh |

Distribution Charges:

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $2.84 per kW during On-Peak hours, plus $0.01095 per kWh | $2.22 per kW, plus $0.01128 per kWh |

Generation Charges:

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $8.16 per kW during On-Peak hours, plus $0.03472 per kWh during On-Peak hours, plus $0.01470 per kWh during Off-Peak hours | $5.78 per kW, plus $0.01259 per kWh |

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

TIME PERIODS

The standard Company On-Peak time period is 9 a.m. to 9 p.m. Monday through Friday. Mountain Standard Time shall be used in the application of this rate schedule.

OPTIONAL TIME PERIODS – TEST PROGRAM

The customer may choose one of the following On-Peak time periods in lieu of the Company's standard On-Peak time period:

7 a.m. – 7 p.m. Monday through Friday
8 a.m. – 8 p.m. Monday through Friday

RATES (cont)

TIME PERIODS (cont)

OPTIONAL TIME PERIODS – TEST PROGRAM (cont):

A maximum of 10,000 customers will be allowed to participate in this test program. The program will be applicable to both Rate Schedule ECT-1R and Rate Schedule ET-1. Customer participation will be subject to meter availability and work schedule constraints.

DETERMINATION OF KW

The kW charges billed in this schedule shall be based on the average kW supplied during the 60-minute period of maximum use during the customer's chosen On-Peak hours during summer months and any hour during winter months, as determined from readings of the Company's meter. In the event the meter is inaccessible to the Company, the kW used for billing shall be estimated using reasonable estimating methodology as determined by the Company. In any billing period in which the kW was estimated, the customer may request a reread and reset of the dial for a charge of $20.00 per trip as long as the request is made within three (3) days of notification from the Company that the kW dial was not read or reset.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE ET-1
# RESIDENTIAL SERVICE TIME-OF-USE
# TIME ADVANTAGE PLAN

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplementary or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

## RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

### Bundled Standard Offer Service

Basic Service Charge: $0.485 per day; plus

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $0.12151 per kWh during On-Peak hours, plus<br>$0.06121 per kWh during Off-Peak hours | $0.06784 per kWh |

The Bundled Standard Offer Service Rate consists of the following Unbundled Components:

### Unbundled Components

Basic Service Charge: $ 0.205 per day

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:

| | | |
|---|---|---|
| Metering | $ 0.163 | per day |
| Meter Reading | $ 0.055 | per day |
| Billing | $ 0.062 | per day |

| | | |
|---|---|---|
| System Benefits Charge: | $ 0.00161 | per kWh |
| Transmission Charge: | $ 0.00476 | per kWh |
| Distribution Charge: | $ 0.02108 | per kWh |

Generation Charges:

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $0.09406 per kWh during On-Peak hours, plus $0.03376 per kWh during Off-Peak hours | $0.04039 per kWh |

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

TIME PERIODS

Standard Company On-Peak time period is 9 a.m. to 9 p.m. Monday through Friday. Mountain Standard Time shall be used in the application of this rate schedule.

OPTIONAL TIME PERIODS – TEST PROGRAM

The customer may choose one of the following On-Peak time periods in lieu of Company's standard On-Peak time period:

7 a.m. – 7 p.m. Monday through Friday
8 a.m. – 8 p.m. Monday through Friday

A maximum of 10,000 customers will be allowed to participate in this test program. The program will be applicable to both Rate Schedule ECT-1R and Rate Schedule ET-1. Customer participation will be subject to meter availability and work schedule constraints.

RATES (cont)

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to a Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

General Service

# RATE SCHEDULE E-30
# GENERAL SERVICE
# EXTRA SMALL UNMETERED

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service where demand and energy requirements are constant, subject to the limitations set forth in the Special Provisions of this schedule. Billing quantities must be subject to accurate determination without the use of metering equipment, and service must be supplied at one point of delivery.

This rate schedule is not applicable to breakdown, standby, supplementary, residential, or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 volts as may be selected by customer subject to availability at the customer's site). The cost of service extension shall include transformation equipment, if required.

## RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.286 per day; plus

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $0.10091 per kWh | $0.09091 per kWh |

The Bundled Standard Offer Service rate consists of the following Unbundled Components:

Unbundled Components

| | | |
|---|---|---|
| Basic Service Charge: | $0.218 | per day |
| Revenue Cycle Service Charges: | | |
| Billing | $0.063 | per day |
| System Benefits Charge: | $0.00177 | per kWh |

RATES (cont)

Unbundled Components (cont)

| | | |
|---|---|---|
| Transmission Charge: | $0.00476 | per kWh |
| Distribution Charge: | $0.03560 | per kWh |

Generation Charges:

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $0.05878 per kWh | $0.04878 per kWh |

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge only. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RATES (cont)

SPECIAL PROVISIONS

1. This rate schedule is applicable only to loads where monthly demand (kW) and energy (kWh) requirements remain constant. Monthly demand and energy requirements may not exceed 1.5 kW or 1,095 kWh at 120 volts or 2.9 kW or 2,117 kWh at 240 volts, for each delivery point. Determination of fixed monthly energy usage will be based on an average 730 hour month.

2. Prior written approval by an authorized Company representative is required before service is implemented under this rate schedule.

3. Prior written approval by an authorized Company representative is required for any change in loads. An unauthorized load change will automatically disqualify that customer from service under this rate schedule.

4. The Company shall have the right to inspect the customer's load facilities at any time to ensure compliance with all provisions of this rate schedule.

CONTRACT PERIOD

Any applicable contract period will be set forth in the Company's standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service required when such service is supplied at one point of delivery and measured through one meter. Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplementary, residential or resale service nor to service for which Rate Schedule E-34 is applicable.

## TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

## RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

FOR MONTHLY MAXIMUM DEMANDS OF 20 kW OR LESS

Bundled Standard Offer Service

Basic Service Charge:

| | | |
|---|---|---|
| For service through Self-Contained Meters: | $ 0.575 | per day |
| For service through Instrument-Rated Meters: | $ 1.134 | per day |
| For service at Primary Voltage: | $ 2.926 | per day, plus |

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF 20 kW OR LESS (cont)

Bundled Standard Offer Service (cont)

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| Secondary Service $0.10095 per kWh | Secondary Service $0.09095 per kWh |
| Primary Service $0.09373 per kWh | Primary Service $0.08373 per kWh |

The Bundled Standard Offer Service rate consists of the following Unbundled Components:

Unbundled Components

| | | |
|---|---|---|
| Basic Service Charge: | $0.108 | per day |
| Revenue Cycle Service Charges: | | |
| Metering: | | |
| Self-Contained Meters: | $ 0.345 | per day |
| Instrument-Rated Meters: | $0.904 | per day |
| Primary: | $ 2.696 | per day |
| Transmission: | $22.192 | per day |
| Meter Reading: | $ 0.058 | per day |
| Billing: | $ 0.064 | per day |
| System Benefits Charge: | $ 0.00177 | per kWh |
| Transmission Charge: | $ 0.00476 | per kWh |
| Distribution Charge: | | |
| Secondary Service | $ 0.03623 | per kWh |
| Primary Service | $ 0.02901 | per kWh |

Generation Charges:

| May - October Billing Cycles (Summer) | November - April Billing Cycles (Winter) |
|---|---|
| $0.05819 per kWh | $0.04819 per kWh |

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF GREATER THAN 20 kW

Bundled Standard Offer Service

Basic Service Charge:

| | | |
|---|---|---|
| For service through Self-Contained Meters: | $0.575 | per day |
| For service through Instrument-Rated Meters: | $1.134 | per day |
| For service at Primary Voltage: | $2.926 | per day |
| For service at Transmission Voltage: | $22.422 | per day, plus |

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| Secondary Service kW Charges<br>$6.348 per kW for the first 500 kW<br>$4.618 per kW for all additional kW | Secondary Service kW Charges<br>$6.348 per kW for the first 500 kW<br>$4.618 per kW for all additional kW |
| Primary Service kW Charges<br>$4.758 per kW for all first 500 kW<br>$3.028 per kW for all additional kW | Primary Service kW Charges<br>$4.758 per kW for all first 500 kW<br>$3.028 per kW for all additional kW |
| Transmission Service kW Charges<br>$1.748 per kW for first 500 kW<br>$0.018 per kW for all additional kW | Transmission Service kW Charges<br>$1.748 per kW for first 500 kW<br>$0.018 per kW for all additional kW |
| Plus Energy Charges<br>$0.08518 per kWh for the first 200 kWh per kW, plus<br>$0.04290 per kWh for all additional kWh | Plus Energy Charges<br>$0.07518 per kWh for the first 200 kWh per kW, plus<br>$0.03290 per kWh for all additional kWh |

MINIMUM

The bill for service under this rate schedule will not be less than the applicable Basic Service Charge plus $1.75 for each kW of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF GREATER THAN 20 kW (cont)

Unbundled Components:

| | | |
|---|---|---|
| Basic Service Charge: | $ 0.108 | per day |
| Revenue Cycle Service Charges: | | |
| Metering: | | |
| Self-Contained Meters: | $ 0.345 | per day |
| Instrument-Rated Meters: | $ 0.904 | per day |
| Primary: | $ 2.696 | per day |
| Transmission: | $22.192 | per day |
| Meter Reading | $ 0.058 | per day |
| Billing | $ 0.064 | per day |
| System Benefits Charge: | $ 0.00172 | per kWh |
| Transmission Charge: | $ 0.00476 | per kWh |

Distribution Charges:

| | |
|---|---|
| Secondary Service kW Charges | $6.348 per kW for the first 500 kW, plus<br>$4.618 per kW for all additional kW |
| Primary Service kW Charges | $ 4.758 per kW for the first 500 kW, plus<br>$ 3.028 per kW for all additional kW |
| Transmission Service kW Charges | $ 1.748 per kW for the first 500 kW, plus<br>$ 0.018 per kW for all additional kW |
| Plus Energy Charges | $ 0.00366 per kWh |

Generation Charges:

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $0.07504 per kWh for the first 200 kWh per kW, plus<br>$0.03276 per kWh for all additional kWh | $0.06504 per kWh for the first 200 kWh per kW, plus<br>$0.02276 per kWh for all additional kWh |

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge only. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

RATES (cont)

DETERMINATION OF KW

The kW charges billed in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the Company's meter.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

For customers with monthly maximum demands less than 2,000 kW, any applicable contract period will be set forth in the Company's standard agreement for service. For customers with monthly maximum demands of 2,000 kW or greater, and at the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-32R
# GENERAL SERVICE
# PARTIAL REQUIREMENTS

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer electric service billed under general service rate schedules to customers not taking all electric power requirements from the Company, but continue to desire a permanent electric connection with the Company as a standby or supplementary power source. All provisions of the otherwise applicable general service rate schedule will apply except those specifically modified herein. Direct Access customers are not eligible for service under this schedule.

This rate schedule is not applicable to breakdown, residential, or resale service nor to service for which Rate Schedules E-34 or E-35 is applicable, or when the customer's other sources of power supply are being held solely for emergency use.

## RATE

Customers being served under this rate schedule will be billed monthly in accordance with the otherwise applicable general service rate with the following exceptions:

A. For electric service billed on standard general service rate schedules the kW charges billed shall be based on the greater of the following:

   1. The average kW supplied during the 15-minute period (or other period as specified by customer contract) of maximum use during the month, as determined from readings of the Company's meter.

   2. 80% of the average of the highest kW measured during each of the six (6) summer billing months (May-October) of the 12 months ending with the current month.

   3. The minimum kW specified in the agreement for service or individual customer contract.

B. For electric service billed on time-of-use general service rate schedules the kW charges billed shall be based on the greater of the following:

   1. The average kW supplied during the 15-minute period (or other period as specified by customer contract) of maximum use during the On-Peak hours of the month, as determined from readings of the Company's meter.

   2. 80% of the average of the highest kW measured during the on-peak hours of the six (6) summer billing months (May-October) of the 12 months ending with the current month.

   3. The minimum kW specified in the agreement for service or individual customer contract.

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service required when such service is supplied at one point of delivery and measured through one meter. Rate Selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt meter.

This schedule is not applicable to breakdown, standby, supplementary, residential or resale service nor to service for which Rate Schedule E-35 is applicable.

## TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

## RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

### FOR MONTHLY MAXIMUM DEMANDS OF 20 kW OR LESS

#### Bundled Standard Offer Service

Basic Service Charge:

| | | |
|---|---|---|
| For service through Self-Contained Meters: | $0.600 | per day |
| For service through Instrument-Rated Meters: | $1.134 | per day |
| For service at Primary Voltage: | $2.926 | per day |

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF 20 kW OR LESS (cont)

Bundled Standard Offer Service (cont)

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| Secondary Service<br>$0.11375 per kWh during On-Peak hours, plus<br>$0.09375 per kWh during Off-Peak hours | Secondary Service<br>$0.09095 per kWh |
| Primary Service<br>$0.10653 per kWh during On-Peak hours, plus<br>$0.08653 per kWh during Off-Peak hours | Primary Service<br>$0.008373 per kWh |

The Bundled Standard Offer Service rate consists of the following Unbundled Components:

Unbundled Components

| | | |
|---|---|---|
| Basic Service Charge: | $0.108 | per day |
| Revenue Cycle Service Charges: | | |
| Metering: | | |
| Self-Contained Meters: | $ 0.370 | per day |
| Instrument-Rated Meters: | $ 0.904 | per day |
| Primary: | $ 2.696 | per day |
| Meter Reading | $ 0.058 | per day |
| Billing | $ 0.064 | per day |
| System Benefits Charge: | $ 0.00177 | per kWh |
| Transmission Charge: | $ 0.00476 | per kWh |
| Distribution Charge: | | |
| Secondary Service | $ 0.03623 | per kWh |
| Primary Service | $ 0.02901 | per KWh |

Generation Charges:

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $0.07099 per kWh during On-Peak hours, plus<br>$0.05099 per kWh during Off-Peak hours | $0.04819 per kWh |

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF GREATER THAN 20 kW:

Bundled Standard Offer Service

Basic Service Charge:

| | | |
|---|---|---|
| For service through Self-Contained Meters: | $0.600 | per day |
| For service through Instrument-Rated Meters: | $1.134 | per day |
| For service at Primary Voltage: | $2.926 | per day |
| For service at Transmission Voltage: | $22.422 | per day, plus |

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| Secondary Service kW Charges<br>$15.046 per kW for the first 500 kW<br>$13.316 per kW for all additional kW | Secondary Service kW Charges<br>$15.046 per kW for the first 500 kW<br>$13.316 per kW for all additional kW |
| Primary Service kW Charges<br>$13.456 per kW for all first 500 kW<br>$11.726 per kW for all additional kW | Primary Service kW Charges<br>$13.456 per kW for all first 500 kW<br>$11.726 per kW for all additional kW |
| Transmission Service kW Charges<br>$10.446 per kW for first 500 kW<br>$ 8.716 per kW for all additional kW | Transmission Service kW Charges<br>$10.446 per kW for first 500 kW<br>$ 8.716 per kW for all additional kW |
| Plus Energy Charges<br>$0.04855 per kWh during On-Peak hours, plus<br>$0.03855 per during Off-Peak hours | Plus Energy Charges<br>$0.03290 per kWh |

In addition to the above charges, if applicable, a Residual Distribution Off-Peak kW charge of $6.783 per kW for secondary service, $5.193 per kW for primary service, or $2.183 per kW for transmission service will be applied to all measured Off-Peak kW that are higher than the measured On-Peak kW for the billing month.

MINIMUM

The bill for service under this rate schedule will not be less than the applicable Basic Service Charge plus $1.75 for each kW of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF GREATER THAN 20 kW (cont)

Unbundled Components

| | | | |
|---|---|---|---|
| Basic Service Charge: | | $ 0.108 | per day |
| Revenue Cycle Service Charges: | | | |
| Metering: | Self-Contained Meters: | $ 0.370 | per day |
| | Instrument-Rated Meters: | $ 0.904 | per day |
| | Primary: | $ 2.696 | per day |
| | Transmission: | $22.192 | per day |
| Meter Reading | | $ 0.058 | per day |
| Billing | | $ 0.064 | per day |
| System Benefits Charge: | | $ 0.00172 | per kWh |
| Transmission Charge: | | $ 0.00476 | per kWh |

Distribution Charges

| | |
|---|---|
| Secondary Service kW Charges | $6.348 per kW for the first 500 kW, plus<br>$4.618 per kW for all additional kW |
| Primary Service kW Charges | $ 4.758 per kW for the first 500 kW, plus<br>$ 3.028 per kW for all additional kW |
| Transmission Service kW Charges | $ 1.748 per kW for the first 500 kW, plus<br>$ 0.018 per kW for all additional kW |
| Plus Energy Charges | $ 0.00366 per kWh |

In addition to the above Distribution charges, if applicable, an Residual Off-Peak kW charge of $6.348 per kW for secondary service, $4.758 per kW for primary service, or $1.748 per kW for transmission service will be applied to all measured Off-Peak kW that are higher than the measured On-Peak kW for the billing month.

Generation Charges:

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $8.698 per On-Peak kW, plus<br>$0.03841 per kWh during On-Peak hours, plus<br>$0.02841 per kWh during Off-Peak hours | $8.698 per On-Peak kW, plus<br>$0.02276 per kWh |

In addition to the above Generation charges, if applicable, a Residual Generation Off-Peak kW charge of $0.435 per kW will be applied to all measured Off-Peak kW that are higher than the measured On-Peak kW for the billing month.

RATES (cont)

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge only. Direct Access customers must acquire and pay for generation and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

DETERMINATION OF KW

The kW charges billed in this schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods of the month, as determined from readings of the Company's meter.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

| | |
|---|---|
| On-Peak hours: | 9:00 am – 9:00 pm Monday through Friday |
| Off-Peak hours: | All remaining hours |

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

For customers with monthly maximum demands less than 2,000 kW, any applicable contract period will be set forth in the Company's standard agreement for service. For customers with monthly maximum demands of 2,000 kW or greater, and at the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-34
# EXTRA LARGE GENERAL SERVICE

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the site served.

## APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose monthly maximum demand registers 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

This schedule is not applicable to breakdown, standby, supplementary or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be three phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the customer's site.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

## RATES

The bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge:

| | | |
|---|---|---|
| For service through Self-Contained Meters: | $ 0.575 | per day |
| For service through Instrument-Rated Meters: | $ 1.134 | per day |
| For service at Primary Voltage: | $ 2.926 | per day |
| For service at Transmission Voltage: | $22.422 | per day, plus |
| Demand Charge: | | |
| Secondary Service | $13.062 | per kW |
| Primary Service | $12.372 | per kW |
| Transmission Service | $ 8.882 | per kW |
| Energy Charge: | $ 0.03284 | per kWh |

RATES (cont)

Unbundled Components

| | | | |
|---|---|---|---|
| Basic Service Charge: | | $ 0.108 | per day |
| Revenue Cycle Service Charges: | | | |
| Metering: | Self-Contained Meters: | $ 0.345 | per day |
| | Instrument-Rated Meters: | $ 0.904 | per day |
| | Primary: | $ 2.696 | per day |
| | Transmission: | $22.192 | per day |
| Meter Reading | | $ 0.058 | per day |
| Billing | | $ 0.064 | per day |
| System Benefits Charge: | | $ 0.00161 | per kWh |
| Transmission Charge: | | $ 0.00476 | per kWh |
| Distribution Charge: | | | |
| Secondary Service | | $ 4.782 | per kW |
| Primary Service | | $ 4.092 | per kW |
| Transmission Service | | $ 0.602 | per kW, plus |
| Energy Charge | | $ 0.00134 | per kWh |
| Generation Charges: | | $ 8.280 | per kW, plus |
| | | $ 0.02513 | per kWh |

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge only. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

DETERMINATION OF KW

The kW charges billed under this schedule shall be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the month, as determined from readings of the Company's meter.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the 12 months ending with the current month.

RATES (cont)

DETERMINATION OF KW (cont)

3. The minimum kW specified in the agreement for service or individual customer contract.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for customers served under this rate schedule will be three (3) years, at the Company's option. If the Company determines that the customer's service location is such that unusual or substantial distribution construction is required to serve the site, the Company may require a contract period of ten (10) years or longer with a standard seven (7) year termination provision.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-35
# EXTRA LARGE GENERAL SERVICE
# TIME OF USE

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the site served.

## APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose monthly maximum demand registers 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

This schedule is not applicable to breakdown, standby, supplementary or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be three phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the customer's site.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

## RATES

The bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

### Bundled Standard Offer Service

| | | |
|---|---|---|
| Basic Service Charge: | | |
| For service through Self-Contained Meters: | $0.600 | per day |
| For service through Instrument-Rated Meters: | $1.134 | per day |
| For service at Primary Voltage: | $2.926 | per day |
| For service at Transmission Voltage: | $22.422 | per day, plus |
| Demand Charge: | | |
| Secondary Service | $13.598 | per On-Peak kW, plus |
| Primary Service | $12.908 | per On-Peak kW |
| Transmission Service | $ 9.418 | per On-Peak kW |
| Energy Charge: | $0.03618 | per kWh during On-Peak hours, plus |
| | $0.02868 | per kWh during Off-Peak hours |

In addition to the above charges, if applicable, an Excess Off-Peak kW charge of $6.717 per kW for secondary service, $6.027 per kW for primary service, or $2.537 per kW for transmission service will be applied to all measured Off-Peak kW that are higher than twice the measured On-Peak kW for the billing month.

RATES (cont)

The Unbundled Standard Offer Service rate consists of the following Unbundled Components:

Unbundled Components

| | | | |
|---|---|---|---|
| Basic Service Charge: | | $ 0.108 | per day |
| Revenue Cycle Service Charges: | | | |
| Metering: | Self-Contained Meters: | $ 0.370 | per day |
| | Instrument-Rated Meters: | $ 0.904 | per day |
| | Primary: | $ 2.696 | per day |
| | Transmission: | $22.192 | per day |
| Meter Reading | | $ 0.058 | per day |
| Billing | | $ 0.064 | per day |
| System Benefits Charge: | | $ 0.00161 | per kWh |
| Transmission Charge: | | $ 0.00476 | per kWh |
| Distribution Charge: | | | |
| Secondary Service | | $ 4.423 | per On-Peak kW, plus |
| Primary Service | | $ 3.733 | per On-Peak kW |
| Transmission Service | | $ 0.243 | per On-Peak kW |
| Energy Charge | | $ 0.00067 | per kWh |

In addition to the above Distribution charges, if applicable, an Excess Distribution Off-Peak kW charge of $4.423 per kW for secondary service, $3.733 per kW for primary service, or $0.243 per kW for transmission service will be applied to all measured Off-Peak kW that are higher than twice the measured On-Peak kW for the billing month.

| | | |
|---|---|---|
| Generation Charges: | $ 9.175 | per On-Peak kW, plus |
| | $ 0.02914 | per kWh during On-Peak hours, plus |
| | $ 0.02164 | per kWh during Off-Peak hours |

In addition to the above Generation charges, if applicable, an Excess Generation Off-Peak kW charge of $2.294 per kW will be applied to all measured Off-Peak kW that are higher than twice the measured On-Peak kW for the billing month.

RATES (cont)

Unbundled Components (cont)

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge only. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

DETERMINATION OF KW

The On-Peak kW charges billed under this schedule shall be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by individual customer contract) of maximum use during the On-Peak period of the month, as determined from readings of the Company's meter.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the 12 months ending with the current month.

The Off-Peak kW charges billed under this schedule shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer contract) of maximum use during the Off-Peak period of the month as determined from readings of the Company's meter.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

| | |
|---|---|
| On-Peak hours: | 9:00 am – 9:00 pm Monday through Friday |
| Off-Peak hours: | All remaining hours |

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

RATES (cont)

ADJUSTMENTS (cont)

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for customers served under this rate schedule will be three (3) years, at the Company's option. If the Company determines that the customer's service location is such that unusual or substantial distribution construction is required to serve the site, the Company may require a contract period of ten (10) years or longer with a standard seven (7) year termination provision.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-53
# GENERAL SERVICE
# ATHLETIC STADIUMS AND SPORTS FIELDS

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to Standard Offer electric service for outdoor athletic stadiums and sports fields operated by schools, churches or municipalities where such service is supplied at one point of delivery and measured through one meter. All provisions of the applicable general service rate schedule will apply except those specifically modified herein. Direct Access customers are not eligible for service under this schedule.

This rate schedule is not applicable to breakdown, standby, supplementary or resale service.

## RATES

Customers being served under this rate schedule will be billed in accordance with the otherwise applicable general service rate with the following exceptions:

1. KW for a minimum bill will be based on the average kW measured during the 15-minute period of maximum use during the current billing month.

2. In those months in which service is not used, no bills will be rendered.

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

To Standard Offer or Direct Access electric service billed under general service rate schedules (except as limited below) where the customer's requirements are distinctly of a recurring seasonal nature, and where the customer enters into an agreement for service with the Company for a sufficient period of time and guarantees payments of a sufficient amount (in no event less than $583.08 in any 12 consecutive months) to justify the Company's expenses for installing service facilities and leaving them in place from season to season.

1. The application of this rate schedule is subject to the following limitations:
2. This schedule is applicable only to electric service billed on Rate Schedule E-32.
3. This schedule is not applicable to breakdown, standby, supplementary, residential or resale service.
4. Customers whose highest measured monthly kW occurs in the billing months of June, July or August are not eligible for this rate schedule.

## RATES

Customers being served under this rate schedule will be billed in accordance with the otherwise applicable general service rate with the following exception:

The minimum bill shall be that minimum specified in the rate schedule, but not more than an amount sufficient to make the total charges for the 12 months ending with the current month equal to twelve times the minimum specified in the rate schedule as calculated on the highest kW established during the 12 months ending with the current month, or the minimum kW specified in an agreement for service, whichever is greater, but in no event less than $583.08.

Classified

# RATE SCHEDULE E-20
# CLASSIFIED SERVICE
# TIME OF USE FOR RELIGIOUS HOUSES OF WORSHIP

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to Standard Offer electric service for non-taxable religious houses of worship whose main purpose is worship and who have an established and continuing membership. Only the meter that measures service to the building in which the sanctuary or principal place of worship is located is eligible for this schedule. Customers must apply to the Company in order to determine eligibility for service under this schedule, and the Company may request a copy of the Internal Revenue Service letter in which the customer's non-taxable status as a religious organization is determined. In addition, customers agree to provide the Company a copy of any Internal Revenue Service letter which changes or supersedes that tax status determination.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt meter.

This schedule is not applicable to breakdown, standby, supplementary, residential or resale service nor to service for which Rate Schedule E-35 is applicable. Direct Access customers are not eligible for this rate schedule.

## TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

## RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

### RATE

Basic Service Charge:

| | |
|---|---|
| For service through Self-Contained Meters: | $0.600 per day |
| For service through Instrument-Rated Meters: | $1.134 per day |

RATES (cont)

RATE (cont)

| May – October Billing Cycles (Summer) | November – April Billing Cycles (Winter) |
|---|---|
| $2.00 per On-Peak kW, plus<br>$0.10122 per kWh during On-Peak hours, plus<br>$0.06873 per kWh during Off-Peak hours | $2.00 per On-Peak kW, plus<br>$0.07638 per kWh during all hours |

In addition to the above charges, if applicable, an Excess Off-Peak kW charge of $1.00 per kW will be applied to all measured Off-Peak kW that are higher than twice the measured On-Peak kW for the billing month.

MINIMUM

The bill for service under this rate schedule will not be less than the applicable Basic Service Charge plus $1.75 for each kW of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

DETERMINATION OF KW

The kW charges billed in this schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods of the month, as determined from readings of the Company's meter.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

| | |
|---|---|
| On-Peak hours: | 9:00 am – 9:00 pm Monday through Friday |
| Off-Peak hours: | All remaining hours |

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

RATES (cont)

ADJUSTMENTS (cont)

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for all customers receiving service under this rate schedule will be one (1) year at the Company's option.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

FROZEN

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

## APPLICATION

This rate schedule is applicable to start-up and/or auxiliary load requirements for generation plants with a Power Supply capacity requirement of greater than 3 MW. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. This rate schedule may be used in conjunction with other applicable Company rate schedules.

## TYPE OF SERVICE

Three phase, 60 Hertz, at one standard voltage available within the vicinity of the customer's site.

## RATES

The bill shall be the sum of the amounts included under A., B. and C. below, including any applicable adjustments:

A. Basic Service

$6,100.00 per month Basic Service Charge

B. Metering Service

1.29% of total metering cost specified in the Electric Supply Agreement between the Company and the customer. This percentage will be reduced to 0.35% when the customer provides all necessary metering equipment and is responsible for its replacement. The customer shall also be responsible for all applicable costs associated with communications facilities used to compile metered usage information.

C. Power Supply Service

The charge for Power Supply Service shall be the sum of 1. and 2. below:

| | | |
|---|---|---|
| 1. T & D Capacity Rate | $4.58 | per kW of Contract Power Supply Capacity for service provided at secondary distribution voltage levels (less than 12.5 kV) |
| | $4.42 | per kW of Contract Power Supply Capacity for service provided at primary distribution voltage levels (12.5 kV to below 69 kV) |
| | $1.43 | per kW of Contract Power Supply Capacity for service provided at transmission voltage levels (69 kV or higher) |
| 2. Power Supply/Energy/Ancillary Service Charge | | Market price plus $0.0005 for each kWh used |

CONTRACT PERIOD

Any applicable contract periods will be set forth in an Electric Supply Agreement between the customer and the Company.

CONNECTION COSTS

The customer will pay all applicable connection costs and system improvement costs not otherwise covered in this schedule as a non-refundable contribution in aid of construction, including any associated tax liability.

POWER SUPPLY CAPACITY

Power Supply Capacity kW shall be defined as the greater of:

(a) The amount of capacity (kW) reserved by the customer in the Electric Supply Agreement; or

(b) The highest 15 minute measured kW supplied by the Company, by voltage level, to accommodate the start-up of the customer's generation unit(s) plus any necessary auxiliary load (including generation auxiliary load and/or any other load requirements at the plant site that would otherwise be provided by the customer when the generation unit(s) are running).

If more than one generation unit is present at a single site, the Electric Supply Agreement may, at the Company's option, allow the customer to start one unit at a time. In this instance, Power Supply Capacity kW shall be defined as the greater of:

(a) The amount of capacity (kW) reserved by the customer in the Electric Supply Agreement; or

(b) The highest 15 minute measured kW supplied by the Company, by voltage level, to accommodate the start-up of one and only one customer generation unit at any given time plus any necessary auxiliary load (including any or all generation auxiliary load and/or any other load requirements at the entire plant site that would otherwise be provided by the customer when any or all generation unit(s) are running).

If, during any one billing period, the highest 15 minute measured kW supplied by the Company (by voltage level) exceeds the amount of Power Supply Capacity specified in the Electric Supply Agreement, the Power Supply Capacity reservation (by voltage level) shall be permanently increased to equal the higher measured kW. If the Company incurs additional connection costs to provide this added capacity, the customer is responsible for payment of these costs as specified herein.

DETERMINATION OF MARKET PRICE

Market price charges shall represent the Company's total cost, as expressed on a per kWh basis, for system incremental power (as determined by the Company or its Scheduling Coordinator) at the time Station Use power is supplied to the customer. The cost for both the generation and purchased power components of the Market Price shall be determined by real time operators on an hourly basis at the time of the operator's power supply source decision(s).

System Incremental Cost shall be computed as the weighted average price of the marginal dispatchable generation resources and/or third party purchases made by the Company's real time operators to serve the specific customer.

METERING

The Company will normally install a supply meter at the point of delivery to the customer and a generator meter(s) at the point(s) of output from each of the customer's generators. However, the customer can elect to supply this metering as long as it conforms to Company specifications. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by the Company.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

INTERCONNECTION REQUIREMENTS

The customer must meet all interconnection requirements as determined by the Company. The customer is responsible for all costs associated with interconnection of the customer's generation facility to the Company's system.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-40
# CLASSIFIED SERVICE
# AGRICULTURAL WIND MACHINE SERVICE

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

## APPLICATION

This rate schedule is applicable to all Standard Offer electric service required for the operation of wind machine for frost control during the months of November thru March only when such service is supplied at one point of delivery and measured through one meter. Direct Access customers are not eligible for this rate schedule.

This schedule is not applicable to temporary, breakdown, standby, supplementary, or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be three phase, 60 Hertz, at one standard voltage (120/240, 120/480, or 7,200/12,000 volts as may be selected by customer subject to availability at the site).

## RATES

| | | |
|---|---|---|
| Basic Service Charge: | $13.37 | per HorsePower per year, plus |
| Energy Charge: | $ 0.06838 | per kWh for all kWh |

HorsePower will be equivalent to the wind machine name plate rating unless Company tests indicate the motor is overloaded by more than 15%.

## ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

1. For billing under this rate schedule, the customer may choose between one of the following options:

   a) Monthly billing;
   b) Semiannual billing for three (3) months in advance and three (3) months actual use; or
   c) Annual billing for six (6) months in advance and six (6) months actual use.

   After initial selection of payment by the customer no change may be made during the term of the service agreement.

2. Thermostatically controlled wind machines with automatic reclosing switches must be equipped at the customer's expense with suitable time-delay devices to permit the required adjustment of the time of reclosure after interruption of service.

   A time-delay device is a relay or other type of equipment that can be preset to delay with various time intervals the reclosing of the automatic switches in order to stagger the reconnection of the load on the utility's system. This device must be constructed so as to effectively permit a variable overall time interval of not less than five minutes with adjustable time increments of not greater than ten seconds. The particular setting to be utilized for each separate installation is to be determined by the Company from time to time in accordance with its operating requirements.

CONTRACT PERIOD

The initial customer contract period shall be five (5) years. The contract period for any renewals shall be three (3) years.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-47
# CLASSIFIED SERVICE
# DUSK to DAWN LIGHTING SERVICE

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to outdoor lighting which operates only from dusk to dawn and where service can be supplied from the existing secondary facilities of the Company. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

## RATES

The customer's bill shall be computed at the following rates for each type of standard facility and/or service utilized to provide outdoor lighting, plus any adjustments incorporated in this schedule:

FIXTURES (Includes Mounting Arm, if Applicable)

| | | | | RATES | |
|---|---|---|---|---|---|
| | Lumen | Watts | kWh | Company Owned | Customer Owned |
| A. Acorn | 9,500 HPS | 100 | 41 | $20.27 | $5.00 |
| | 16,000 HPS | 150 | 69 | 22.45 | 6.71 |
| B. Architectural | 9,500 HPS | 100 | 41 | 14.32 | 6.41 |
| | 16,000 HPS | 150 | 69 | 16.65 | 8.59 |
| | 30,000 HPS | 250 | 99 | 19.66 | 10.94 |
| | 50,000 HPS | 400 | 153 | 24.13 | 15.16 |
| | 14,000 MH | 175 | 72 | 19.07 | 10.22 |
| | 21,000 MH | 250 | 101 | 21.58 | 12.53 |
| | 36,000 MH | 400 | 159 | 26.87 | 17.07 |
| | 8,000 LPS | 55 | 30 | 20.59 | 7.80 |
| | 13,500 LPS | 90 | 50 | 24.20 | 9.16 |
| | 22,500 LPS | 135 | 72 | 27.57 | 11.17 |
| | 33,000 LPS | 180 | 90 | 31.77 | 12.99 |
| C. Cobra/Roadway | 5,800 HPS | 70 | 29 | 8.34 | 5.47 |
| | 9,500 HPS | 100 | 41 | 9.73 | 6.41 |
| | 16,000 HPS | 150 | 69 | 12.07 | 8.59 |
| | 30,000 HPS | 250 | 99 | 14.45 | 10.94 |
| | 50,000 HPS | 400 | 153 | 19.42 | 15.16 |
| | 14,000 MH | 175 | 72 | 11.39 | 7.97 |
| | 21,000 MH | 250 | 101 | 13.25 | 9.78 |
| | 36,000 MH | 400 | 159 | 17.31 | 13.32 |
| | 8,000 FL | 100 | 38 | 13.03 | 3.58 |

RATES (cont)

FIXTURES (Includes Mounting Arm, if Applicable) (cont)

| | | | | | RATES | |
|---|---|---|---|---|---|---|
| | | Lumen | Watts | kWh | Company Owned | Customer Owned |
| D. Decorative Transit | Pedestrian (4") | 9,500 HPS | 100 | 41 | $27.63 | $5.00 |
| | Pedestrian (6") | 9,500 HPS | 100 | 41 | 27.63 | 5.00 |
| | Streetlight (6") | 30,000 HPS | 250 | 99 | 31.57 | 8.54 |
| E. Flood | | 30,000 HPS | 250 | 99 | 18.28 | 10.94 |
| | | 50,000 HPS | 400 | 153 | 22.56 | 15.16 |
| | | 21,000 MH | 250 | 101 | 16.55 | 9.78 |
| | | 36,000 MH | 400 | 159 | 20.09 | 13.32 |
| F. Post Top | Colonial Gray | 8,000 FL | 100 | 38 | 14.01 | 3.58 |
| | | 9,500 HPS | 100 | 41 | 10.02 | 6.41 |
| | Colonial Black | 9,500 HPS | 100 | 41 | 11.03 | 6.41 |
| | Decorative Transit | 9,500 HPS | 100 | 41 | 24.24 | 5.00 |
| G. FROZEN | | 4,000 INC | 295 | 103 | 10.23 | 3.78 |
| | | 7,000 MV | 175 | 73 | 10.33 | 4.97 |
| | | 20,000 MV | 400 | 150 | 14.35 | 9.47 |

FROZEN

NOTES:

1. Company Owned fixtures are those fixtures that the Company installs, owns, operates, and maintains.
2. Customer Owned fixtures are those fixtures where the customer installs and maintains the lighting fixtures, and the Company approves the installation, operates the fixtures, and replaces Company standard lamps only.
3. Listed kWh's reflect the assigned monthly usage kWh's for each type of fixture and are used to determine any applicable transmission, distribution, energy and adjustment charges.
4. HPS = High Pressure Sodium
5. MH = Metal Halide
6. LPS = Low Pressure Sodium
7. FL = Fluorescent
8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those customers being served and those installations in service on April 21, 1983.
9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those customers being served and those installation in service on June 1, 1987 in accordance with A.R.S. §49-1104(A).

RATES (cont)

POLES

| | | | Height | RATES Company Owned |
|---|---|---|---|---|
| A. Anchor Base Mounted (Flush) | Round Steel | 1 Simplex Adapter | 12 ft. | $ 8.68 |
| | | | 22 ft. | 9.80 |
| | | | 25 ft | 10.63 |
| | | | 30 ft | 12.25 |
| | | | 32 ft | 12.88 |
| | Round Steel | 2 Simplex Adapters | 12 ft. | 9.27 |
| | | | 22 ft. | 10.69 |
| | | | 25 ft. | 11.16 |
| | | | 30 ft. | 13.01 |
| | | | 32 ft. | 13.90 |
| | Square Steel | 5" | 13 ft. | 9.99 |
| | | | 15 ft. | 8.90 |
| | | | 23 ft. | 10.60 |
| | | | 25 ft. | 11.68 |
| | | | 28 ft. | 12.99 |
| | | | 32 ft. | 13.47 |
| | Concrete | | 12 ft. | 30.26 |
| | Fiberglass | | 12 ft. | 25.59 |
| | Decorative Transit Pedestrian | 4" | 16 ft. | 24.94 |
| | Decorative Transit | 6" | 30 ft. | 25.48 |
| B. Anchor Base Mounted (Pedestal) | Round Steel | 1 Simplex Adapter | 12 ft. | 8.34 |
| | | | 22 ft. | 9.46 |
| | | | 25 ft. | 10.28 |
| | | | 30 ft. | 11.91 |
| | | | 32 ft. | 12.53 |
| | Round Steel | 2 Simplex Adapters | 12 ft. | 8.93 |
| | | | 22 ft. | 10.00 |
| | | | 25 ft. | 10.82 |
| | | | 30 ft. | 12.67 |
| | | | 32 ft. | 13.55 |
| | | 3 Bolt Arm | 32 ft. | 15.61 |
| | Square Steel | 5" | 13 ft. | 9.65 |
| | | | 15 ft. | 9.88 |
| | | | 23 ft. | 10.26 |
| | | | 25 ft. | 11.34 |
| | | | 28 ft. | 12.64 |
| | | | 32 ft. | 13.13 |

RATES (cont)

POLES (cont)

| | | | Height | RATES Company Owned |
|---|---|---|---|---|
| C. Direct Bury | Round Steel | | 19 ft. | 13.27 |
| | | | 30 ft. | 12.54 |
| | | | 38 ft. | 15.34 |
| | | Self Support | 40 ft. | 18.19 |
| | | Stepped | 49 ft. | 47.44 |
| | Square Steel | 4" | 34 ft. | 13.85 |
| | | 5" | 20 ft. | 12.62 |
| | | | 30 ft. | 13.71 |
| | | | 38 ft. | 14.89 |
| | Steel Distribution Pole | | 35 ft. | 17.02 |
| D. Post Top | Decorative Transit Anchor Base | | 16 ft. | 25.48 |
| | Gray Steel/Fiberglass | | 23 ft. | 10.57 |
| | Black Steel | | 23 ft. | 11.20 |
| E. FROZEN | Wood Poles | | 30 ft. | 6.08 |
| | | | 35 ft. | 7.66 |
| | | | 40 ft. | 9.70 |

FROZEN

NOTES:

1. All distribution lines required to serve dusk to dawn facilities are owned by the Company.
2. Monthly rates for all new Company owned poles include up to 100 feet of overhead secondary wire, or up to 100 feet of underground secondary line if customer provides earthwork and conduit (excluding the overhead to underground transition). Any additional wire required (over and above the first 100 feet provided) to install fixtures is subject to the additional monthly wire charges specified in below.
3. When adding lighting fixtures to an existing Company owned pole, any and all additional distribution wire required is subject to the additional monthly wire charges specified below.
4. Any and all distribution wire required to serve lighting facilities placed on a customer owned pole, whether new or existing, is subject to the additional monthly wire charges specified below.

ANCHOR BASE

| | | Height | RATES Company Owned |
|---|---|---|---|
| A. Flush | | 4 ft. | $7.27 |
| | | 6 ft. | 8.67 |
| B. Pedestal | | 8 ft. | 9.94 |
| | For 32' Round Steel Pole only | 4 ft. 6" | 6.89 |

RATES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

| | RATES Company Owned |
|---|---|
| 1. Each 100 feet of overhead secondary wire, or each 100 feet of underground secondary wire if customer provides earthwork and conduit. | 2.57 |
| 2. Additional maintenance charge for HPS lamp and luminaire that is not accessible by bucket truck. | 2.05 |
| 3. Additional maintenance charge for MH lamp and luminaire that is not accessible by bucket truck. | 4.43 |

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

1. The 4,000 and 7,000 lumen lamps use an open glass diffuser. All units are controlled by a photoelectric switch.

2. The customer is not authorized to make connections to the lighting circuits or to make attachments.

3. Should a customer request relocation of a dusk-to-dawn lighting installation, the costs of such relocation shall be paid by the customer.

4. The Company cannot guarantee that all dusk to dawn facilities will always operate as intended. Therefore, the customer will be responsible for notifying the Company when the dusk to dawn facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by customer; however, if the maintenance requires cable replacement or repairs, the Company shall use reasonable efforts to complete said repairs within twenty (20) working days.

5. The customer's bills will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

6. The customer may cancel a lighting service agreement by payment of the bill including the applicable tax adjustment, multiplied by the number of remaining months of the initial agreement, or the calculated installation and removal costs for the extension, whichever is lower.

NON-STANDARD FACILITIES – CUSTOMER OWNED

When the customer requests any non-standard dusk-to-dawn lighting facilities (non-standard being defined as any equipment not listed in the Company's Transmission and Distribution Construction Standards book), the customer will own, operate and maintain all components to the system excluding the distribution facilities installed by the Company to serve the lighting system. Bills rendered for non-standard facilities will be computed at the following rates, plus any adjustments incorporated in this schedule:

| | | | |
|---|---|---|---|
| A. | Service Charge per installed lamp | $2.56, plus | |
| B. | Energy Charge | $0.04847 | per kWh |

If, at the Company's discretion, the customer chooses to have the Company maintain the entire non-standard facility, the Company may require the customer to enter into a separate maintenance agreement which may be subject to additional charges mutually agreed upon by the Company and the customer.

CONTRACT PERIOD

All Dusk-to-Dawn lighting installations will require a written agreement for service for a minimum of three (3) years, or longer at Company's option.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-51
# CLASSIFIED SERVICE
# OPTIONAL ELECTRIC SERVICE FOR QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES OVER 100 kW

FROZEN

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable only to qualified cogeneration and small power production facilities greater than 100 kW that meet qualifying status as defined under 18 CFR, Chapter 1, Part 292, Subpart B of the Federal Energy Regulatory Commission regulations and pursuant to the Arizona Corporation Commission's Decision No. 52345. The facility's generator(s) and load must be located at the same site.

Applicable only to those customers being served on the Company's Rate Schedule E-51 prior to July 1, 1996.

## TYPE OF SERVICE

Single or three phase, 60 Hertz, at one standard voltage as may be selected by Customer subject to availability at Customer's premise.

## RATES

The bill shall be the sum of the amounts computed under A., B., C., and D. below, including the applicable Adjustments:

A. Basic Service
$ 0.263 per day Cogeneration Basic Service Charge, plus
$ 0.789 per day per each generator meter

B. Supplemental Service
In accordance with the rate levels contained in General Service Rate Schedule E-32 or E-34, whichever is applicable based upon Customer's maximum Supplemental demand.

C. Standby Service

1. Monthly Reservation Charge of $1.98 per kW of Contract Standby Capacity, to be adjusted as specified on page 2, plus

2. Standby Energy Charge:

| | |
|---|---|
| May - October Billing Cycles (Summer) | $0.04383 per kWh On-Peak<br>$0.02040 per kWh Off-Peak |
| November - April Billing Cycles (Winter) | .02234 per kWh |

RATES(cont)

D. Maintenance Service

$0.02040 per kWh of maintenance energy

DETERMINATION OF MONTHLY RESERVATION CHARGE

For initial service, the Monthly Reservation Charge shall be: the product of [$19.79/kW multiplied by a Forced Outage Rate (FOR) of 10%] multiplied by the customer's applicable Contract Standby Capacity. At the end of the first 6 summer billing months, the initial FOR of 10% will be replaced by the actual FOR experienced by the cogeneration system during on-peak summer hours. Customer's summer on-peak FOR will then be reevaluated annually each November for the preceding 12-month period to be used in the calculation of Customer's Reservation Charge for the current and succeeding 11 months.

DETERMINATION OF SUPPLEMENTAL SERVICE

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by Customer's generation facility.

Supplemental demand shall be equal to the maximum 15 minute integrated kW demand as calculated for every 15-minute interval as the demand of the Supply meter plus the demand of the Generator meter(s) less the Contract Standby Capacity of Customer's cogenerator(s).

Supplemental energy shall be equal to all energy supplied to Customer as determined from readings of the Supply meter, less any energy determined to be either Standby or Maintenance energy as defined in this Schedule.

DETERMINATION OF STANDBY ENERGY

Standby Energy shall be defined to be electric energy supplied by Company to replace power ordinarily generated by Customer's generation facility during unscheduled full and partial outages of said facility.

When the sum of the energy measured on both the Supply and Generator(s) Meters is greater than the maximum energy output of the generator(s) at Contract Standby Capacity, the Standby Energy shall be equal to the summation of the differences between the maximum energy output of the generator(s) at Contract Standby Capacity and the energy measured on the Generator Meter(s) for every 15-minute interval of the month, except when maintenance power is being utilized or those intervals where energy measured on the Supply Meter is zero. When the sum of the energy measured on both the Supply and Generator(s) Meters is less than the maximum energy output of the generator(s) at Contract Standby Capacity, then the Standby energy shall be that energy measured on the Supply Meter.

All Standby Energy exceeding 250 kWh/kW of Contract Standby Capacity in a billing period will be billed at the otherwise applicable rate for Supplemental Service.

RATES (cont)

DETERMINATION OF MAINTENANCE ENERGY

Maintenance energy shall be defined as energy supplied to Customer up to a maximum of the Contract Standby Capacity times the hours in the Scheduled Maintenance period for that energy used only during the Scheduled Maintenance period. Maintenance periods shall not exceed 30 days per cogeneration unit during any consecutive 12-month period and must be scheduled during the winter billing months. Customer shall supply Company with Maintenance Schedule for a 12-month period at least 60 days prior to the beginning of that period, which shall be subject to Company approval. Energy used in excess of a 30-day period or unauthorized maintenance energy shall be billed on either the Standby or Supplemental Rate as specified in this Schedule.

METERING

The Company will install a Supply Meter at its point of delivery to Customer and a Generator Meter(s) at the point(s) of output from each of Customer's generators. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by Company.

DEFINITIONS

1. Contract Standby Capacity - the measured kW output of each cogeneration unit at time of start-up test, which will be re-evaluated annually each November and specified in Customer's Agreement for Service, however, not to exceed Customer's actual total load.

2. Forced Outage Rate - the ratio of the standby energy used during the Customer's summer on-peak hours to the product of the Contract Standby Capacity multiplied by the total customer's summer on-peak hours.

3. Generator Meter - the time-of-use meter used to measure in 15-minute intervals the total power and energy output of each of Customer's cogeneration units.

4. Supply Meter - the time-of-use meter used to measure in 15-minute intervals the total power and energy supplied by Company to Customer.

5. Time Periods - On-Peak Period: 9 a.m. - 9 p.m. Monday through Friday
   Off-Peak Period: All Other Hours

   Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)



FROZEN

ADJUSTMENTS (cont)

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMINATION PROVISION

Should Customer cease to operate his cogeneration unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in Company's Agreement for Service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-52
# CLASSIFIED SERVICE
# ELECTRIC SERVICE FOR PARTIAL REQUIREMENTS SERVICE OF LESS THAN 3,000 kW

## AVAILABILITY

This rate schedule is available in all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

## APPLICATION

Applicable to any non-residential customer requiring Partial Requirements services, Supplemental Power, Standby Power or Maintenance Energy with an aggregate Partial Requirements service load of less than 3,000 kW. Customer may elect to take any of the Partial Requirements services offered hereunder, Supplemental Power, Standby Power and Maintenance Power independently of one another or in combination with one another as required.

Each customer shall be allowed to designate the specific periods and hours within a month for which utilization of Standby Service is required (see Designated Standby Service Hours).

## TYPE OF SERVICE

Single or three phase, 60 Hertz, at one standard voltage as may be selected by Customer subject to availability at Customer's premise.

## RATES

The bill shall be the sum of the amounts computed under A., B., C., and D. below, including the applicable Adjustments:

A. Basic Service
   $ 106.79 per month Basic Service Charge, plus
   $ 17.06 per month for each Generator Meter

B. Supplemental Service
   In accordance with the rate levels contained in General Service Rate Schedule E-32 excluding the monthly Basic Service Charge.

C. Standby Service
   The monthly charge for Standby Service shall be the sum of the amounts computed in accordance with sections 1 and 2 below:

RATES (cont)

C. Standby Service (cont)

1. Monthly Reservation Charge of either a, b or c:

   a) $5.01 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor of 90% or greater during the billing month.

   b) $6.59 per kW of contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor between 80% - 89.9% during the billing month.

   c) Standby Service customers whose alternate supply resource(s) achieved an aggregate capacity factor of less than 80% during a billing month shall be assessed the same charge as set forth in Section VIII of this rate schedule.

2. Standby Energy Charge:

| | |
|---|---|
| June - October Billing Cycles (Summer) | $0.02961 per kWh on-peak<br>$0.01574 per kWh off-peak |
| November - May Billing Cycles (Winter) | $0.02537 per kWh on-peak<br>$0.01006 per kWh off-peak |

The charges for Standby Service contained in Section C herein reflect the Company's costs to serve Standby Service loads. For applications where the charges for Standby Service stated herein are not competitive with customer installed standby resource alternatives, the Company may negotiate alternate Monthly Reservation Charges from those contained in this rate schedule; however, the maximum discount allowed shall not be greater than fifty percent (50%) of the Reservation Charges stated herein; however, such discount shall not result in a reservation charge lower than the Company's long run capacity costs associated with this service. No changes to the Standby Energy Charge rate component shall be allowed.

To be eligible for negotiated Monthly Reservation Charges different than those contained herein, the customer must demonstrate to the Company's satisfaction and provide conclusive documentation (e.g., engineering studies, analysis, etc.) that the customer's on-site self-generation resource(s) would be a lower cost option over the life of the equipment than had the customer subscribed to Standby Service from the Company. Notwithstanding the potential competitiveness of the customer's self generation standby facilities, the Company in its sole opinion, shall have the option of not offering any discounts to the otherwise applicable Reservation Charge.

RATES (cont)

D. Maintenance Service
$0.02537 per kWh on-peak
$0.01006 per kWh off-peak

E. Energy Rates
The energy rates in Sections C and D above are based on the Company's estimated marginal costs and will be updated annually to reflect changes in the Company's fuel costs.

DETERMINATION OF SUPPLEMENTAL SERVICE

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by Customer's generation facility.

Supplemental demand shall be the highest 15-minute interval during the billing month which shall equal the (a) 15-minute integrated kW demand calculated for every 15-minute interval as recorded on the Supply Meter, plus (b) the simultaneous 15 minute integrated kW demand as recorded on the Generator Meter(s), less (c) the aggregate Contract Standby Capacity of all the customer's generating units; however, the result shall never be less than zero (0) for purposes of determining Supplemental Demand. If Company authorized scheduled maintenance was being performed on any of the customer's generators at the time of the highest 15 minute interval during the billing month, the amount of demand recorded on the Supply Meter shall be reduced by the applicable Maintenance Power Level (as determined in Section VII hereof) of the generator unit(s) undergoing authorized scheduled maintenance for purposes of calculating supplemental demand used for billing.

Customer's maximum Supplemental Service kW requirements shall not exceed that established in the Electric Supply Agreement.

Supplemental energy shall be equal to all energy supplied to Customer as determined from readings of the Supply Meter, less any energy determined to be either Standby or Maintenance energy as defined in this Schedule.

DETERMINATION OF STANDBY ENERGY

Standby Energy shall be defined to be electric energy supplied by Company to replace power ordinarily generated by Customer's generation facility during unscheduled full and partial outages of said facility.

When the sum of the energy measured on both the Supply and Generator(s) Meters during simultaneous periods is greater than the maximum energy output of the generator(s) at Contract Standby Capacity, the Standby Energy shall be equal to the summation of the differences between the maximum energy output of the generator(s) at Contract Standby Capacity and the energy measured on the Generator Meter(s) for every 15-minute interval of the month, except when maintenance power is being utilized or those intervals where energy measured on the Supply Meter is zero. When the sum of the energy measured on both the Supply and Generator(s) Meter is equal to or less than the maximum energy output of the generator(s) at Contract Standby Capacity, then the Standby energy shall be that energy measured on the Supply Meter.

DETERMINATION OF MAINTENANCE ENERGY

Maintenance energy shall be defined as energy supplied to Customer to replace energy normally supplied by the Customer's generator(s) during an authorized Scheduled Maintenance period.

Maintenance periods shall not exceed 30 days per cogeneration unit during any consecutive 12-month period and must be scheduled during the non-Summer billing months. Customer shall provide Company with its planned maintenance schedule 12 months in advance of any planned maintenance in order for the Company to coordinate customer's scheduled maintenance with that of the Company. Upon review, Company shall either approve customer's planned maintenance schedule or notify customer of alternate acceptable periods. Customer, in turn, shall notify the Company of an acceptable alternate maintenance period(s), and shall also confirm with the Company its intention to perform its planned maintenance 45 days prior to the actual commencement date of the planned maintenance period.

Any energy used in excess of a 30-day period or unauthorized maintenance energy shall be billed on either the Standby or Supplemental Rate as specified in this Schedule.

Maintenance energy, during a Company authorized period of scheduled maintenance to a customer's generation unit(s), shall be determined as follows:

Maintenance Power Level = (Contract Standby Capacity) X (Generating Unit(s) Capacity Factor for the most recent 12 months)

The maintenance power level as determined by the above formula shall not exceed any actual 15 minute interval of integrated kW demand as recorded on the supply meter.

If customer has less than 12 months of billing history on Standby Service, use the capacity factor demonstrated to date; however, not less than one full month.

Maintenance Energy = (Maintenance Power Level) X (hours of maintenance authorized by Company during billing month)

CAPACITY FACTOR STANDARDS

Customer's generating unit(s) must maintain a Capacity Factor of no less than 75% over a continuous rolling 18 month period to remain eligible to receive Standby Service under this rate schedule. The calculation of the Capacity Factor is designed so that the customer shall not be subject to this Capacity Factor Standard provision for any purpose other than substandard operational performance of the customer's generating unit(s) recognizing that the customer's load profile may not require the full output capability of such generation unit(s). If the Capacity Factor falls below 75%, in lieu of the otherwise applicable Reservation Charge for Standby Service, the customer shall be assessed a monthly Reservation Charge the greater of:

1. $18.79 per kW/month X 2/3 X Contract Standby Capacity; or

2. $18.79 per kW/month X Maximum Standby Capacity
(If customer's system is directly interconnected with the Company's bulk transmission system, the applicable Reservation Charge shall be $14.39 per kW per month.)

CAPACITY FACTOR STANDARDS (cont)

Maximum Standby Capacity is intended to represent the maximum 15-minute interval of Standby Power provided the customer by the Company during the billing month. Maximum Standby Capacity shall equal the highest 15-minute interval during the billing month of the following calculation:

$$MSC = \Sigma CSC - Maint.$$

Where:

MSC = Maximum 15-minute interval during the billing month of Standby Power (kW) being supplied by Company.

ΣCSC = The aggregate Contract Standby Capacity of all the customer's self-generation units.

Maint = The simultaneous 15-minute interval of any Maintenance Power (kW) being supplied to customer by the Company.

METERING

The Company will install a Supply Meter at its point of delivery to Customer and a Generator Meter(s) at the point(s) of output from each of Customer's generators. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by Company.

DEFINITIONS

1. Contract Standby Capacity - for each specific customer generating unit for which the Company is providing Standby Service, Contract Standby Capacity shall be the greater of: a) the measured kW output of each customer self-generation unit at time of start-up test, or b) the highest 15 minute measured kW output of each generating unit, however, not to exceed Customer's actual total load.

2. Generator Meter - the time-of-use meter used to measure in 15-minute intervals the total power and energy output of each cogeneration unit.

3. Designated Standby Service Hours - Customers requiring Standby Service for less than the total hours in a billing month shall be allowed to designate those periods and hours of a month when Standby Service is required. These Designated Standby Service Hours shall represent those hours within a billing month during which the customer is authorized to utilize Standby Service. Use during any period or hours other than Designated Standby Service Hours shall represent an Unauthorized Use of Standby Service subject to certain special provisions for determining the appropriate Capacity Factor value during billing periods when unauthorized Standby Service was utilized. Such hours shall be specified in whole hour intervals beginning on an hour for each designated day of the week. Designated Standby Service Hours shall never total less than 280 hours a billing month.

DEFINITIONS (cont)

4. Capacity Factor - for purposes of this rate schedule, capacity factor shall mean the capacity factor of the customer's generating unit(s) and shall not reflect any period of time during a billing month that Company authorized Maintenance Power was being utilized. The Capacity factor shall be calculated in accordance with the following formula:

$$\text{Capacity Factor} = \frac{\text{Actual customer generated kWh's during the billing month}}{A}$$

For purposes of use in this rate schedule, the value of the capacity factor calculation shall never exceed 100%.

Where:

A = The lesser of:
a) [(Contract Standby Capacity) X (MH)]; or
b) CTL

MH = The number of Designated Standby Service Hours in the billing month, exclusive of any hours during the billing month that customer's unit(s) were non-operational during Company authorized scheduled maintenance, for which the customer has contracted for Standby Service (but not less than 280 hours per billing month).

In the event the customer utilizes Standby Service in any period other than during Designated Standby Service Hours, MH shall be represented as the actual number of hours in the billing month (exclusive of any hours during which the customer was receiving Company authorized scheduled Maintenance Energy).

Furthermore, in the event there are more than two (2) instances in any 12 month rolling period of Unauthorized Use of Standby Service, MH shall be represented as the actual number of hours in the billing month (exclusive of any hours during which the customer was receiving Company authorized scheduled Maintenance Energy) for the month during which the third breach of service occurred, and for the next three months thereafter. At the end of any three month breach period, a new twelve (12) month rolling period shall commence for determining the number of instances of Unauthorized Use.

CTL = Customer's maximum total load during the billing month during the Designated Standby Service Hours for which the Customer has contracted for Standby Service (but not less than 280 hours per month).

CTL shall represent the customer's maximum total load during the hours in the billing month for which use of Standby Service has been authorized as set forth in the definition of Designated Standby Service Hours. CTL shall be calculated by first adding the maximum simultaneous 15-minute kW peak periods as recorded on the Supply Meter and Generator Meter(s) during authorized periods of Standby Service the sum of which is then multiplied by MH.

In the event the customer utilizes Standby Service during any period of a billing month other than those authorized, CTL shall represent the customer's maximum total (peak demand) load during the billing month calculated as the sum of the maximum simultaneous 15-minute kW peak period during the billing period recorded on the Supply Meter and the Generator Meter(s) during all hours of the billing month. CTL shall be similarly calculated for any other months during which the provision for breach of service explained in the definition of MH above is being assessed.

CTL shall only be used for calculating Capacity Factor in those months where the customer's maximum kW load is less than total Contract Standby Capacity.

5. Supply Meter - the time-of-use meter used to measure in 15-minute intervals the total power and energy supplied by Company to Customer.

6. Time Periods -

| | |
|---|---|
| On-Peak Period: | 9 a.m. - 9 p.m. Monday through Friday |
| Off-Peak Period: | All Other Hours |

Mountain Standard Time shall be used in the application of this rate schedule. In addition, to prevent radical changes in the system loads the beginning and ending hours for individual customers may be varied by up to one hour (total hours in each time period to remain unchanged) and because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

ADJUSTMENT (cont)

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMINATION PROVISION

Should Customer cease to operate his cogeneration unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

Customer must enter into an Agreement for the Interconnection and The Sale of Power with Company and an Electric Supply Agreement which shall establish all pertinent details related to interconnection and other required service standards. Customer will not have the option to sell power and energy to Company under this tariff. Should Customer desire to do so, Customer would be required to enter into a new Service Agreement which would set forth the applicable purchase rate in addition terms and conditions for interconnection and for the sale of power to the Company.

Customer will be required to contract for adequate standby power to cover the total output of all the customer's generators unless adequate facilities have been installed, to the satisfaction of APS, that isolate portions of the customer's load from APS' system so that APS will in no event be providing standby service in excess of Contracted Standby Capacity.

CHANGE IN DESIGNATED STANDBY SERVICE HOURS

Customers shall be allowed no more than one (1) change in their Designated Standby Service Hours during any eighteen (18) month time period. In no event shall the total of Designated Standby Service Hours during a month fall below 280 hours.

# RATE SCHEDULE E-55
# CLASSIFIED SERVICE
# ELECTRIC SERVICE FOR PARTIAL REQUIREMENTS SERVICE 3,000 kW OR GREATER

## AVAILABILITY

In all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

## APPLICATION

Applicable to any customer requiring Partial Requirements services, Supplemental Power, Standby Power or Maintenance Energy with an aggregate Partial Requirements service load of no less than 3,000 kW. Customer may elect to take any of the Partial Requirements services offered hereunder (Supplemental Power, Standby Power and Maintenance Power) independently of one another or in combination with one another as required.

Customers having Standby Service requirements not exceeding 2,999 kW shall be allowed to designate specific periods and hours within a month for which utilization of Standby Service is required (see Designated Standby Service Hours).

## TYPE OF SERVICE

Single or three phase, 60 Hertz, at one standard voltage as may be selected by Customer subject to availability at Customer's premise.

## RATES

The bill shall be the sum of the amounts computed under A., B., C., and D. below, including the applicable Adjustments:

A. Basic Service

1. a) For applications no greater than 15,000 kW:

   $ 1,671.39 per month Basic Service Charge; plus

   b) For applications greater than 15,000 kW:

   The monthly Basic Service Charge shall be $1,671.39 plus an applicable adder for recovery of non-standard metering costs and related O&M expenses; plus

2. $ 62.51 per month for each Generator Meter

B. Supplemental Service

In accordance with the rate levels contained in General Service Rate Schedule E-32, excluding the monthly Basic Service Charge (or E-34 if Supplemental Power requirements are 3,000 kW or more).

RATES(cont)

C. Standby Service

The monthly charge for Standby Service shall be the sum of the amounts computed in accordance with sections 1, 2 and 3 below:

1. For customers taking service at voltage levels of less than 69 kV, a Monthly Reservation Charge of either a, b, c or d:

   a) $ 4.21 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor of 95% or greater during the billing month.

   b) $ 5.14 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor between 90% - 94.9% during the billing month.

   c) $ 6.77 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor between 80% - 89.9% during the billing month.

   d) Standby Service customers whose alternate supply resource(s) achieved an aggregate capacity factor of less than 80% during a billing month shall be assessed the same charge as set forth in Section VIII.A of this rate schedule.

2. For customers who take service at voltage levels of 69 kV or greater, a Monthly Reservation Charge of either a, b, c or d:

   a) $ 1.45 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor of 95% or greater during the billing month.

   b) $ 2.30 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor between 90% - 94.9% during the billing month.

   c) $ 4.11 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor between 80% - 89.9% during the billing month.

   d) Standby Service customers whose alternate supply resource(s) achieved an aggregate capacity factor of less than 80% during a billing month shall be assessed the same charge as set forth in Section VIII.B of this rate schedule.

RATES (cont)

Standby Service (cont)

3. Standby Energy Charge:

| | | |
|---|---|---|
| June - October Billing Cycles (Summer) | $0.03040 | per kWh On-peak |
| | $0.01616 | per kWh Off-peak |
| November - May Billing Cycles (Winter) | $0.02605 | per kWh on-peak |
| | $0.01033 | per kWh off-peak |

The charges for Standby Service contained in Section C herein reflect the Company's costs to serve Standby Service loads. For applications where the charges for Standby Service stated herein are not competitive with customer installed standby resource alternatives, the Company may negotiate alternate Monthly Reservation Charges from those contained in this rate schedule; however, the maximum discount allowed shall not be greater than fifty percent (50%) of the Reservation Charges stated herein; however, such discount shall not result in a reservation charge lower than the Company's long run capacity costs associated with this service. No changes to the Standby Energy Charge rate component shall be allowed.

To be eligible for negotiated Monthly Reservation Charges different than those contained herein, the customer must demonstrate to the Company's satisfaction and provide conclusive documentation (e.g., engineering studies, analysis, etc.) that the customer's on-site self-generation resource(s) would be a lower cost option over the life of the equipment than had the customer subscribed to Standby Service from the Company. Notwithstanding the potential competitiveness of the customer's self generation standby facilities, the Company in its sole opinion, shall have the option of not offering any discounts to the otherwise applicable Reservation Charge.

D. Maintenance Service

| | |
|---|---|
| $0.02605 | per kWh On-peak |
| $0.01033 | per kWh Off-peak |

E. Energy Rates

The energy rates in Sections C and D above are based on the Company's estimated marginal costs and will be updated annually to reflect changes in the Company's fuel costs.

DETERMINATION OF SUPPLEMENTAL SERVICE

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by Customer's generation facility.

DETERMINATION OF SUPPLEMENTAL SERVICE (cont)

Supplemental demand shall be the highest 15-minute interval during the billing month which shall equal the (a) 15-minute integrated kW demand calculated for every 15-minute interval as recorded on the Supply Meter, plus (b) the simultaneous 15 minute integrated kW demand as recorded on the Generator Meter(s), less (c) the aggregate Contract Standby Capacity of all the customer's generating units; however, the result shall never be less than zero (0) for purposes of determining Supplemental Demand. If Company authorized scheduled maintenance was being performed on any of the customer's generators at the time of the highest 15 minute interval during the billing month, the amount of demand recorded on the Supply Meter shall be reduced by the applicable Maintenance Power Level (as determined in Section VII hereof) of the generator unit(s) undergoing authorized scheduled maintenance for purposes of calculating supplemental demand used for billing.

Customer's maximum Supplemental Service kW requirements shall not exceed that established in the Electric Supply Agreement.

Supplemental energy shall be equal to all energy supplied to Customer as determined from readings of the Supply Meter, less any energy determined to be either Standby or Maintenance energy as defined in this Schedule.

DETERMINATION OF STANDBY ENERGY

Standby Energy shall be defined to be electric energy supplied by Company to replace power ordinarily generated by Customer's generation facility during unscheduled full and partial outages of said facility.

When the sum of the energy measured on both the Supply and Generator(s) Meters during simultaneous periods is greater than the maximum energy output of the generator(s) at Contract Standby Capacity, the Standby Energy shall be equal to the summation of the differences between the maximum energy output of the generator(s) at Contract Standby Capacity and the energy measured on the Generator Meter(s) for every 15-minute interval of the month, except when maintenance power is being utilized or those intervals where energy measured on the Supply Meter is zero. When the sum of the energy measured on both the Supply and Generator(s) Meter is equal to or less than the maximum energy output of the generator(s) at Contract Standby Capacity, then the Standby energy shall be that energy measured on the Supply Meter.

DETERMINATION OF MAINTENANCE ENERGY

Maintenance energy shall be defined as energy supplied to Customer to replace energy normally supplied by the Customer's generator(s) during an authorized Scheduled Maintenance period.

Maintenance periods shall not exceed 30 days per cogeneration unit during any consecutive 12-month period and must be scheduled during the non-Summer billing months. Customer shall provide Company with its planned maintenance schedule 12 months in advance of any planned maintenance in order for the Company to coordinate customer's scheduled maintenance with that of the Company. Upon review, Company shall either approve customer's planned maintenance schedule or notify customer of alternate acceptable periods. Customer, in turn, shall notify the Company of an acceptable alternate maintenance period(s), and shall also confirm with the Company its intention to perform its planned maintenance 45 days prior to the actual commencement date of the planned maintenance period.

Any energy used in excess of a 30-day period or unauthorized maintenance energy shall be billed on either the Standby or Supplemental Rate as specified in this Schedule.

DETERMINATION OF MAINTENANCE ENERGY (cont)

Maintenance energy, during a Company authorized period of scheduled maintenance to a customer's generation unit(s), shall be determined as follows:

Maintenance Power Level = (Contract Standby Capacity) X (Generating Unit(s) Capacity Factor for the most recent 12 months)

The maintenance power level as determined by the above formula shall not exceed any actual 15 minute interval of integrated kW demand as recorded on the supply meter.

If customer has less than 12 months of billing history on Standby Service, use the capacity factor demonstrated to date; however, not less than one full month.

Maintenance Energy = (Maintenance Power Level) X (hours of maintenance authorized by Company during billing month)

CAPACITY FACTOR STANDARDS

Customer's generating unit(s) must maintain a Capacity Factor of no less than 75% over a continuous rolling 18 month period to remain eligible to receive Standby Service under this rate schedule. The calculation of the Capacity Factor is designed so that the customer shall not be subject to this Capacity Factor Standard provision for any purpose other than substandard operational performance of the customer's generating unit(s) recognizing that the customer's load profile may not require the full output capability of such generation unit(s). If the Capacity Factor falls below 75%, in lieu of the otherwise applicable Reservation Charge for Standby Service, the customer shall be assessed a monthly Reservation Charge the greater of:

A. For customers taking service at voltage levels of less than 69 kV:

1. $ 21.28 per kW/month X 2/3 X Contract Standby Capacity; or

2. $ 21.28 per kW/month X Maximum Standby Capacity (If customer's system is directly interconnected with the Company's bulk transmission system, the applicable Reservation Charge shall be $ 18.05 per kW per month.)

B. For customers who take service at voltage levels of 69 kV or greater:

1. $ 18.94 per kW/month X 2/3 X Contract Standby Capacity; or

2. $ 18.94 per kW/month X Maximum Standby Capacity (If customer's system is directly interconnected with the Company's bulk transmission system, the applicable Reservation Charge shall be $ 18.11 per kW per month.)

Maximum Standby Capacity is the maximum 15-minute interval of Standby Power provided the customer by the Company during the billing month. Maximum Standby Capacity shall equal the highest 15-minute interval during the billing month of the following calculation:

CAPACITY FACTOR STANDARDS (cont)

$$MSC = \Sigma CSC - Maint.$$

Where:

MSC = Maximum 15-minute interval during the billing month of Standby Power (kW) being supplied by Company.

ΣCSC = The aggregate Contract Standby Capacity of all the customer's self-generation units.

Maint = The simultaneous 15-minute interval of any Maintenance Power (kW) being supplied to customer by the Company.

METERING

The Company will install a Supply Meter at its point of delivery to Customer and a Generator Meter(s) at the point(s) of output from each of Customer's generators. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by Company.

DEFINITIONS

1. Contract Standby Capacity - for each specific customer generating unit for which the Company is providing Standby Service, Contract Standby Capacity shall be the greater of a) the measured kW output of each customer self-generation unit at time of start-up test, or b) the highest 15 minute measured kW output of each generating unit, however, not to exceed Customer's actual total load.

2. Generator Meter - the time-of-use meter used to measure in 15-minute intervals the total power and energy output of each cogeneration unit.

3. Designated Standby Service Hours - Customers requiring Standby Service for less than the total hours in a billing month shall be allowed to designate those periods and hours of a month when Standby Service is required. These Designated Standby Service Hours shall represent those hours within a billing month during which the customer is authorized to utilize Standby Service. Use during any period or hours other than Designated Standby Service Hours shall represent an Unauthorized Use of Standby Service subject to certain special provisions for determining the appropriate Capacity Factor value during billing periods when unauthorized Standby Service was utilized. Such hours shall be specified in whole hour intervals beginning on an hour for each designated day of the week. Designated Standby Service Hours shall never total less than 365 hours a billing month. This provision is applicable only to those customers whose Standby Service requirements are less than 3,000 kW.

4. Capacity Factor - for purposes of this rate schedule, capacity factor shall mean the capacity factor of the customer's generating unit(s) and shall not reflect any period of time during a billing month that Company authorized Maintenance Power was being utilized. The Capacity factor shall be calculated in accordance with the following formula:

DEFINITIONS (cont)

Capacity Factor (cont)

$$\text{Capacity Factor} = \frac{\text{Actual customer generated kWh's during the billing month}}{A}$$

For purposes of use in this rate schedule, the value of the capacity factor calculation shall never exceed 100%.

Where:

A = The lesser of: a) [(Contract Standby Capacity) X (MH)]; or
b) CTL

Customers having Standby Service Requirements of 3,000 kW or greater:

MH = Hours in the billing month exclusive of any hours during the billing month that customer's unit(s) were non-operational during Company authorized scheduled maintenance.

CTL = Customer's maximum total load during the billing month as determined by the total of energy generated on customer's generating unit as recorded on the Generator Meter plus all energy provided by Company during the billing month (exclusive of maintenance energy) as recorded on the Supply Meter.

Customers having Standby Service Requirements of less than 3,000 kW:

MH = The number of Designated Standby Service Hours in the billing month, exclusive of any hours during the billing month that customer's unit(s) were non-operational during Company authorized scheduled maintenance, for which the customer has contracted for Standby Service (but not less than 365 hours per billing month).
In the event the customer utilizes Standby Service in any period other than during Designated Standby Service Hours, MH shall be represented as the actual number of hours in the billing month (exclusive of any hours during which the customer was receiving Company authorized scheduled Maintenance Energy).

Furthermore, in the event there are more than two (2) instances in any 12 month rolling period of Unauthorized Use of Standby Service, MH shall be represented as the actual number of hours in the billing month (exclusive of any hours during which the customer was receiving Company authorized scheduled Maintenance Energy) for the month during which the third breach of service occurred, and for the next three months thereafter. At the end of any three month period, a new twelve (12) month rolling period shall commence for determining the number of instances of Unauthorized Use.

CTL = Customer's maximum total load during the billing month during the Designated Standby Service Hours for which the Customer has contracted for Standby Service (but not less than 365 hours per month).as determined by the total of energy generated on customer's generating unit as recorded on the Generator Meter plus all energy provided by Company

DEFINITIONS (cont)

Capacity Factor (cont)

during the billing month (exclusive of maintenance energy) as recorded on the SupplyMeter.

CTL shall represent the customer's maximum total load during the hours in the billing month for which use of Standby Service has been authorized as set forth in the definition of Designated Standby Service Hours. CTL shall be calculated by first adding the maximum simultaneous 15-minute kW peak periods as recorded on the Supply Meter and Generator Meter(s) during authorized periods of Standby Service the sum of which is then multiplied by MH.

In the event the customer utilizes Standby Service during any period of a billing month other than those authorized, CTL shall represent the customer's maximum total load (peak demand) during the billing month calculated as the sum of the maximum simultaneous 15-minute kW peak period during the billing period recorded on the Supply Meter and the Generator Meter(s) during all hours of the billing month. CTL shall be similarly calculated for any other months during which the provision for breach of service explained in the definition of MH above is being assessed.

CTL shall only be used for calculating Capacity Factor in those months where the customer's maximum kW load is less than total Contract Standby Capacity.

5. Supply Meter — the time-of-use meter used to measure in 15-minute intervals the total power and energy supplied by Company to Customer.

6. Time Periods - On-Peak Period: 9 a.m. - 9 p.m. Monday through Friday
Off-Peak Period: All Other Hours

Mountain Standard Time shall be used in the application of this rate schedule. In addition, to prevent radical changes in the system loads the beginning and ending hours for individual customers may be varied by up to one hour (total hours in each time period to remain unchanged) and because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

7. Unauthorized Use - any period or hour of the month that the customer utilized Standby Service other than Designated Standby Service Hours.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

ADJUSTMENTS(cont)

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMINATION PROVISION

Should Customer cease to operate his cogeneration unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

Customer must enter into an Agreement for the Interconnection and The Sale of Power with Company and an Electric Supply Agreement which shall establish all pertinent details related to interconnection and other required service standards. Customer will not have the option to sell power and energy to Company under this tariff. Should Customer desire to do so, Customer would be required to enter into a new Service Agreement which would set forth the applicable purchase rate in addition terms and conditions for interconnection and for the sale of power to the Company.

Customer will be required to contract for adequate standby power to cover the total output of all the customer's generators unless adequate facilities have been installed, to the satisfaction of APS, that isolate portions of the customer's load from APS' system so that APS will in no event be providing standby service in excess of Contracted Standby Capacity.

CHANGE IN DESIGNATED STANDBY SERVICE HOURS

Customers for which Designated Standby Service Hours is applicable shall be allowed no more than one (1) change in their Designated Standby Service Hours during any eighteen (18) month time period. In no event shall the total of Designated Standby Service Hours during a month fall below 365 hours.

## AVAILABILITY

This rate schedule is available in those portions of cities, towns and unincorporated communities in which Company does a general retail electric business and where Company has installed a multiple or series street lighting system of adequate capacity for the service to be rendered.

## APPLICATION

This rate schedule is applicable to service for lighting public streets, alleys, thoroughfares, public parks and playgrounds from dusk to dawn by use of Company's facilities where such service for the whole area is contracted for from the Company by the city, town, other governmental agencies, or a responsible individual for unincorporated communities. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

## RATES

The bill shall be computed at the following rates for each type of standard facility and/or service utilized to provide street lighting, plus any adjustments incorporated in this schedule:

FIXTURES (Includes Mounting Arm, if Applicable)

| | | | | RATES | |
|---|---|---|---|---|---|
| | Lumen | Watts | kWh | Investment by Company | Investment by Others |
| A. Acorn | 9,500 HPS | 100 | 41 | $19.86 | $6.76 |
| | 16,000 HPS | 150 | 69 | 22.04 | 8.55 |
| B. Architectural | 9,500 HPS | 100 | 41 | 11.75 | 5.60 |
| | 16,000 HPS | 150 | 69 | 13.73 | 7.51 |
| | 30,000 HPS | 250 | 99 | 16.29 | 9.63 |
| | 50,000 HPS | 400 | 153 | 20.09 | 13.30 |
| | 14,000 MH | 175 | 72 | 15.79 | 8.65 |
| | 21,000 MH | 250 | 101 | 17.92 | 10.67 |
| | 36,000 MH | 400 | 159 | 22.41 | 14.67 |
| | 8,000 LPS | 55 | 30 | 17.09 | 7.20 |
| | 13,500 LPS | 90 | 50 | 20.15 | 8.69 |
| | 22,500 LPS | 135 | 72 | 23.02 | 10.60 |
| | 33,000 LPS | 180 | 90 | 26.58 | 12.49 |
| C. Cobra/Roadway | 5,800 HPS | 70 | 29 | 6.67 | 3.95 |
| | 9,500 HPS | 100 | 41 | 7.86 | 4.83 |
| | 16,000 HPS | 150 | 69 | 9.84 | 6.74 |
| | 30,000 HPS | 250 | 99 | 11.87 | 8.76 |
| | 50,000 HPS | 400 | 153 | 16.09 | 12.51 |

FIXTURES (Includes Mounting Arm, if Applicable) (cont):

| | | | | | RATES | |
|---|---|---|---|---|---|---|
| | | Lumen | Watts | kWh | Investment by Company | Investment By Others |
| C. Cobra/Roadway (cont.) | | 14,000 MH | 175 | 72 | $10.98 | $7.49 |
| | | 21,000 MH | 250 | 101 | 12.84 | 9.31 |
| | | 36,000 MH | 400 | 159 | 16.90 | 12.94 |
| | | 8,000 FL | 100 | 38 | 12.62 | 3.70 |
| D. Decorative Transit | Pedestrian (4") | 9,500 HPS | 100 | 41 | 27.22 | 8.15 |
| | Pedestrian (6") | 9,500 HPS | 100 | 41 | 27.22 | 8.15 |
| | Streetlight (6") | 30,000 HPS | 250 | 99 | 31.16 | 11.76 |
| E. Flood | | 30,000 HPS | 250 | 99 | 15.12 | 9.40 |
| | | 50,000 HPS | 400 | 153 | 18.75 | 13.04 |
| | | 21,000 MH | 250 | 101 | 16.14 | 9.93 |
| | | 36,000 MH | 400 | 159 | 19.68 | 13.47 |
| F. Post Top | Colonial Gray | 8,000 FL | 100 | 38 | 13.60 | 3.84 |
| | | 9,500 HPS | 100 | 41 | 8.10 | 4.88 |
| | Colonial Black | 9,500 HPS | 100 | 41 | 8.96 | 5.05 |
| | Decorative Transit | 9,500 HPS | 100 | 41 | 23.83 | 7.51 |

| | | | | | | |
|---|---|---|---|---|---|---|
| G. FROZEN | | 4,000 INC | 295 | 103 | 6.88 | 6.88 |
| | | 7,000 MV | 175 | 73 | 8.91 | 5.11 |
| | | 11,000 MV | 250 | 96 | 11.16 | 6.80 |
| | | 20,000 MV | 400 | 150 | 17.52 | 9.93 |

FROZEN

NOTES:

1. Investment by Company. These rates are applicable where the Company provides the initial investment to purchase and install all facilities necessary for street lighting service. The Company will own, operate, and maintain the street lighting system.
2. Investment by Others. These rates are applicable in those instances where the requesting entity or individual purchases and installs the street lighting facilities at their own expense and in accordance with Company specifications. These rates will also apply in the instance where the customer provides a non-refundable advance to the Company to cover the Company's cost of purchasing and installing the street lighting system. The Company retains ownership of the street lighting system and provides operation and maintenance for all facilities.
3. Listed kWh's reflect the assigned monthly usage kWh's for each type of fixture and are used to determine any applicable transmission, distribution, energy and adjustment charges.
4. HPS = High Pressure Sodium
5. MH = Metal Halide
6. LPS = Low Pressure Sodium
7. FL = Fluorescent
8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those customers being served and those installations in service on November 1, 1986.
9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those customers being served and those installation in service on November 1, 1986 in accordance with A.R.S. §49-1104(A).

POLES

| | | | Height | RATES Investment by Company | RATES Investment By Others |
|---|---|---|---|---|---|
| A. Anchor Base Mounted (Flush) | Round Steel | 1 Simplex Adapter | 12 ft. | $8.93 | $1.23 |
| | | | 22 ft. | 10.05 | 1.38 |
| | | | 25 ft. | 10.88 | 1.50 |
| | | | 30 ft. | 12.50 | 1.72 |
| | | | 32 ft. | 13.13 | 1.81 |
| | | 2 Simplex Adapters | 12 ft. | 9.52 | 1.31 |
| | | | 22 ft. | 10.94 | 1.51 |
| | | | 25 ft. | 11.41 | 1.57 |
| | | | 30 ft. | 13.26 | 1.83 |
| | | | 32 ft. | 14.15 | 1.95 |
| | Square Steel | 5" | 13 ft. | 10.24 | 1.41 |
| | | | 15 ft. | 9.15 | 1.26 |
| | | | 23 ft. | 10.85 | 1.49 |
| | | | 25 ft. | 11.93 | 1.64 |
| | | | 28 ft. | 13.24 | 1.82 |
| | | | 32 ft. | 13.72 | 1.89 |
| | Concrete | | 12 ft. | 30.51 | 4.20 |
| | Fiberglass | | 12 ft. | 25.84 | 3.56 |
| | Decorative Transit Pedestrian | 4" | 16 ft. | 25.19 | 3.47 |
| | Decorative Transit | 6" | 30 ft. | 25.73 | 3.54 |
| B. Anchor Base Mounted (Pedestal) | Round Steel | 1 Simplex Adapter | 12 ft. | 8.59 | 1.18 |
| | | | 22 ft. | 9.71 | 1.34 |
| | | | 25 ft. | 10.53 | 1.45 |
| | | | 30 ft. | 12.16 | 1.68 |
| | | | 32 ft. | 12.78 | 1.76 |
| | | 2 Simplex Adapters | 12 ft. | 9.18 | 1.26 |
| | | | 22 ft. | 10.25 | 1.41 |
| | | | 25 ft. | 11.07 | 1.52 |
| | | | 30 ft. | 12.92 | 1.78 |
| | | | 32 ft. | 13.80 | 1.90 |
| | | 3 Bolt Arm | 32 ft. | 15.86 | 2.18 |
| | Square Steel | 5" | 13 ft. | 9.90 | 1.36 |
| | | | 15 ft. | 10.13 | 1.39 |
| | | | 23 ft. | 10.51 | 1.45 |
| | | | 25 ft. | 11.59 | 1.60 |
| | | | 28 ft. | 12.89 | 1.78 |
| | | | 32 ft. | 13.38 | 1.84 |

POLES (cont)

| | | | Height | RATES Investment by Company | RATES Investment By Others |
|---|---|---|---|---|---|
| C. Direct Bury | Round Steel | | 19 ft. | 13.52 | 1.86 |
| | | | 30 ft. | 10.99 | 2.03 |
| | | | 38 ft. | 13.42 | 2.08 |
| | | Self Support | 40 ft. | 15.86 | 2.62 |
| | | Stepped | 49 ft. | 47.69 | 6.57 |
| | Square Steel | 4" | 34 ft. | 12.14 | 2.11 |
| | | 5" | 20 ft. | 11.06 | 1.83 |
| | | | 30 ft. | 12.00 | 1.98 |
| | | | 38 ft. | 13.03 | 2.26 |
| | Steel Distribution Pole | | 35 ft. | 17.27 | 2.38 |
| D. Post Top | Decorative Transit Anchor Base | | 16 ft. | 25.73 | 3.54 |
| | Gray Steel/Fiberglass | | 23 ft. | 9.30 | 1.53 |
| | Black Steel | | 23 ft. | 9.84 | 1.62 |
| E. FROZEN | Wood Poles | | 30 ft. | 6.83 | 1.14 |
| | | | 35 ft. | 6.83 | 1.14 |

FROZEN

NOTE: The monthly rate for all new poles includes up to 300 feet of overhead secondary wire, or up to 300 feet of underground secondary wire if the customer provides earthwork and conduit (excluding the underground to overhead transition).

ANCHOR BASE

| | | Height | RATES Investment by Company | RATES Investment By Others |
|---|---|---|---|---|
| A. Flush | | 4 ft. | $7.27 | $1.00 |
| | | 6 ft. | 8.67 | 1.50 |
| B. Pedestal | | 8 ft. | 9.94 | 1.73 |
| | For 32' Round Steel Pole only | 4 ft. 6" | 6.89 | 1.20 |

CHARGES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

| | RATES Company Owned |
|---|---|
| Underground Circuit Charges: | |
| a. Per foot of cable, installed under paving | 0.11910 |
| b. Per foot of cable, not installed under paving | 0.04236 |

FROZEN

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

1. Street lighting facilities installed under this rate schedule are of the type currently being furnished by Company as standard at the time service is initially requested. Standard facilities are those listed in the Company's Transmission and Distribution Construction Standards book.

2. The Company cannot guarantee that streetlighting facilities will always operate as intended. Therefore, the customer will be responsible for notifying the Company when the streetlighting facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by customer; however, if the maintenance requires cable replacement or repairs, the Company shall use reasonable efforts to complete said repairs within twenty (20) working days.

3. The customer's monthly bills will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

NON-STANDARD FACILITIES

Non-standard facilities (non-standard being defined as any facility not listed in the Company's Transmission and Distribution Construction Standards book) do not qualify for this rate schedule. At the Company's discretion, such facilities may be served under another of the Company's rate schedules.

EXTENSION OF STREET LIGHTING SYSTEM

The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the customer. When the extension is underground the customer will provide earthwork as specified in Section 6.1.2 of the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the customer's request, the Company will provide such earthwork for a contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# GOVERNMENT OWNED STREET LIGHTING SYSTEMS

## AVAILABILITY

This rate schedule is available in those portions of cities, towns and unincorporated communities in which the Company does a general retail electric business and where the customer has installed or purchased a multiple or series street lighting system and the Company has distribution facilities of adequate capacity for the service to be rendered.

## APPLICATION

This rate schedule is applicable to Standard Offer electric service for lighting public streets, alleys, thoroughfares, public parks and playgrounds from dusk to dawn by use of the customer's facilities where such service for the whole area is contracted for from the Company pursuant to the terms set forth herein by the city, town, other governmental entities, or a responsible individual for unincorporated communities. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

The customer will own, operate, and maintain the street lighting system including lamps and glass replacements but excluding distribution facilities installed by the Company to serve the lighting system.

## RATES

The bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

| | | |
|---|---|---|
| Service Charge: | $2.56 | per installed lamp; plus |
| Energy Charge: | $0.04847 | per kWh |

## ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

Billed energy is based upon the summation of the contracted energy rating of installed facilities specified in the streetlighting contract.

The customer's bills will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

Presently installed units which do not conform to the types specified in Rate Schedule E-58 will be billed in accordance with the type which is most nearly like such units.

EXTENSION OF COMPANY DISTRIBUTION SYSTEM

The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the customer. When the extension is underground the customer will provide earthwork as specified in Section 6.1.2 of the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the customer's request, the Company will provide such earthwork for a contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

CONTRACT PERIOD

The contract period for service under this rate schedule shall be a fixed period of not less than 1 year and not more than 20 years, as agreed to by the customer and as specified in the streetlighting contract.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-66
# CLASSIFIED SERVICE – SHARE THE LIGHT
# LITCHFIELD PARK STREET LIGHTING

FROZEN

AVAILABILITY

In the Town of Litchfield Park.

APPLICATION

To electric service billed under the applicable Street Lighting Schedule E-58.

All provisions of the Street Lighting Schedule E-58 will apply except as specifically modified herein.

Service under this rate schedule is limited to those street lights installed prior to April 8, 1980. The Company is not obligated to install new light fixtures, poles or distribution circuits, but will continue to maintain and operate those installed prior to April 8, 1980 only while maintenance and replacement materials are available from Company stock or until this rate schedule is cancelled, whichever comes first, provided, however, under no circumstances shall poles be relocated. Interfering poles shall only be removed. The Company is authorized to collect from the sponsoring entity, any and all unpaid bills for street lighting service.

THE STREET LIGHTING SYSTEM

The Company has installed at its own expense, a street lighting system as prescribed by Litchfield Park Properties, a subsidiary of Goodyear Tire & Rubber Company.

The Company agrees to submit all requests for increases or decreases in number or size of lamps, change in location, or like matters, for each subdivision, to Litchfield Park Properties for approval before any action is taken by the Company.

RATES

Customers to be assessed for street lighting shall include all customers of Arizona Public Service Company located within the following subdivisions or geographic areas:

1. Geographic Area Number 1 described as:

   E 1/2 of the SE 1/4 of the NE 1/4, Section 21, T 2 N, R 1 W, the E 1/2 of the SE 1/4, Section 21, T 2 N, R 1 W; the SW 1/4, Section 22, T 2 N, R 1 W; the N 1/2 of the NW 1/4, Section 27, T 2 N, R 1 W and the N 1/2 of the NE 1/4, Section 28, T2 N, R 1 W, except area within Litchfield Park Subdivision #10, all in Township 2 north, Range 1 West.

2. Litchfield Park Subdivision #10.

3. Litchfield Park Subdivision #12.

   Each of the above subdivisions or geographic areas is, for rate purposes, to be considered as a separate Street Lighting Area.

The following method is to be used to compute the individual residential and commercial street lighting monthly charge, for each subdivision or geographic area.

The monthly charge for street lighting for each subdivision or geographic area with street lighting is to be divided by a figure equal to the total number of residential customers for the month, plus six times the total number of commercial and industrial customers. The assessment is to be adjusted to the nearest cent. Each subdivision or geographic area residential customer is to be assessed the amount of the individual assessment as determined by the above method. Each subdivision or geographic area commercial or industrial customer is to be assessed six times the amount of the individual assessment as determined by the above method. The above assessment will be added to the customer's monthly bill for service.

One meter in each business house is to be counted as a commercial or industrial customer and one meter in each residence as a residential customer, regardless of the number of meters installed on the customer's premises to serve any such commercial, industrial or residential customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# MUNICIPAL LIGHTING SERVICE – CITY OF PHOENIX

## AVAILABILITY

This rate schedule is available within the City of Phoenix at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to Standard Offer electric service furnished for the lighting of alleys, buildings, and other public places owned or maintained by the City. Streetlighting service is not eligible for this schedule. Service to traffic signals is limited to those installations being served as of January 31, 1985, under the Agreement of April 4, 1930, as modified, between Central Arizona Light and Power Company and the City of Phoenix, and no new or reconnected traffic signal installations may be served after that time. Service must be supplied at one site through one point of delivery and measured through one meter. Direct Access service is not available under this rate schedule.

This schedule is not applicable to breakdown, standby, supplementary, or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage (as may be selected by customer, subject to availability at the customer's site).

## RATES

The bill shall be computed at the following rate plus any adjustments incorporated in this schedule:

### RATE

$0.04128 per kWh for all kWh

### ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-114
# CLASSIFIED SERVICE – SHARE THE LIGHT
# LOWER MIAMI AND CLAYPOOL LIGHTING SERVICE

FROZEN

## AVAILABILITY

This rate schedule is available only in the area now known as Claypool and Lower Miami near Miami.

## APPLICATION

To electric service billed under the applicable Street Lighting Schedule E-58.

All provisions of the Street Lighting Schedule E-58 will apply except as specifically modified herein.

Service under this rate schedule is limited to those street lights installed prior to April 8, 1980. The Company is not obligated to install new light fixtures, poles or distribution circuits, but will continue to maintain and operate those installed prior to April 8, 1980 only while maintenance and replacement materials are available from Company stock or until this rate schedule is cancelled, whichever comes first, provided, however, under no circumstances shall poles be relocated. Interfering poles shall only be removed. The Company is authorized to collect from the sponsoring entity, any and all unpaid bills for street lighting service.

## THE STREET LIGHTING SYSTEM

The Company has installed, at its own expense, a street lighting system as prescribed by the Tri-City Fire Department.

The Company agrees to submit all requests for increases or decreases in number or size of lamps, change in location, or like matters regarding Claypool and Lower Miami street lights to the Tri-City Fire Department for approval before any action is taken by the Company.

## BILLING

Customers to be assessed for street lighting shall include all customers of Arizona Public Service Company located within the area now known as Claypool and Lower Miami comprising the following area: The NW 1/4 of Section 29; the NE 1/4, SW 1/4 of Section 29; the North half of NE 1/4, Section 29; the SE 1/4, SW 1/4, Section 20; the South half of SE 1/4, Section 20, the SW 1/4, SW 1/4 of Section 21; the East half of SW 1/4 of Section 21; the NW 1/4, NW 1/4, Section 28; all of Township 1 North, Range 15 East, of the G & SRB & M.

The monthly charge for street lighting is to be divided by a figure equal to the total number of residential customers for the month, plus three times the total number of commercial and industrial customers. The assessment is to be adjusted to the nearest cent. Each Claypool and Lower Miami residential customer is to be assessed the amount of the individual assessment as determined by the above method. Each Claypool and Lower Miami commercial and industrial customer is to be assessed three times the amount of individual assessment as determined by the above method. The above assessment will be added to the customer's monthly bill for service.

Only one meter in each business house is to be counted as a commercial or industrial customer and one meter in each residence as a residential customer, regardless of the number of meters installed on the customer's premises to serve any such commercial, industrial or residential customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-116
# CLASSIFIED SERVICE – SHARE THE LIGHT
# CENTRAL HEIGHTS AND COUNTRY CLUB MANOR
# STREET LIGHTING

PROPOSED

## AVAILABILITY

In the area now known as Central Heights and Country Club Manor near Miami.

## APPLICATION

To electric service billed under the applicable Street Lighting Schedule E-58.

All provisions of the Street Lighting Schedule E-58 will apply except as specifically modified herein.

Service under this rate schedule is limited to those streetlights installed prior to April 8, 1980. The Company is not obligated to install new light fixtures, poles or distribution circuits, but will continue to maintain and operate those installed prior to April 8, 1980 only while maintenance and replacement materials are available from Company stock or until this rate schedule is cancelled, whichever comes first, provided, however, under no circumstances shall poles be relocated. Interfering poles shall only be removed. The Company is authorized to collect from the sponsoring entity, any and all unpaid bills for street lighting service.

## THE STREET LIGHTING SYSTEM

The Company has installed, at its own expense, a street lighting system as prescribed by the Central Heights Fire Department.

The Company agrees to submit all requests for increases or decreases in number or size of lamps, change in location, or like matters regarding Central Heights street lights to the Central Heights Fire Department for approval before any action is taken by the Company.

## BILLING

Customers to be assessed for street lighting shall include all customers of Arizona Public Service Company located within the area now know as Central Heights, consisting of the SE 1/4 of Section 22, S 1/2 of NE 1/4 of Section 22 and the E 1/2 of SW 1/4 of Section 22, Township 1, Range 15 E., G & SRB & M and within the area now known as County Club Manor, consisting of the entire S 1/2 of the NW 1/4 of Section 22, Township 1 N, Range 15 E., G & SRB & M.

The monthly charge for street lighting is to be divided by a figure equal to the total number of residential, commercial and industrial customers. The assessment is to be adjusted to the nearest cent. Each Central Heights and Country Club Manor residential, commercial and industrial customer will be assessed a like amount as determined by the above described method. The above assessment will be added to the customer's monthly bill for service.

Only one meter in each residence or business house is to be counted as a residential, commercial or industrial customer regardless of the number of meters installed on the customer's premises to serve any such residential, commercial or industrial customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-145
# CLASSIFIED SERVICE – SHARE THE LIGHT
# AJO HEIGHTS STREET LIGHTING

PROPOSED

## AVAILABILITY

In the area now known as Ajo Heights near Ajo.

## APPLICATION

To electric service billed under the applicable Street Lighting Schedule E-58.

All provisions of the Street Lighting Schedule E-58 will apply except as specifically modified herein.

Service under this rate schedule is limited to those streetlights installed prior to April 8, 1980. The Company is not obligated to install new light fixtures, poles or distribution circuits, but will continue to maintain and operate those installed prior to April 8, 1980 only while maintenance and replacement materials are available from Company stock or until this rate schedule is cancelled, whichever comes first, provided, however, under no circumstances shall poles be relocated. Interfering poles shall only be removed. The Company is authorized to collect from the sponsoring entity, any and all unpaid bills for street lighting service.

## THE STREET LIGHTING SYSTEM

The Company will install, at its own expense, a street lighting system as prescribed by the Ajo Heights Chamber of Commerce.

The Company agrees to submit all requests for increases or decreases in number or size of lamps, change in location, or like matters regarding Ajo Heights street lights to the Ajo Heights Chamber of Commerce for approval before any action is taken by the Company.

## BILLING

For purposes of assessment, each Ajo Heights commercial or industrial customer is to be considered equivalent to six Ajo Heights residential customers. Ajo Heights customers to be assessed for street lighting shall include all residential, commercial, or industrial customers of the Company located within the following area:

The area known as Ajo Heights consisting of Section 10; the NW Quarter, the NE Quarter, and the SW Quarter of Section 15; the NW Quarter of the SE Quarter of Section 15; the West 450 feet of the SW Quarter of the SE Quarter of Section 15; the NW Quarter of Section 22; and the NW Quarter of the NW Quarter of Section 14; all located in T 12 S, R 6 W of the G & SRB & M.

The monthly charge for street lighting is to be divided by a figure equal to the total number of residential customers for the month, plus six times the number of commercial customers. This assessment is to be adjusted to the nearest cent. Each Ajo Heights residential customer is to be assessed the amount of the individual assessment as determined by the above method. Each Ajo Heights commercial customer is to be assessed six times the amount of the individual assessment as determined by the above method. The above assessment will be added to the customer's bill for service.

Only one meter in each business house is to be counted as a commercial customer and one meter in each residence as a residential customer, regardless of the number of meters installed on the customer's premises to serve any such commercial or residential customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

FROZEN

# RATE SCHEDULE E-221
# CLASSIFIED SERVICE
# WATER PUMPING SERVICE

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to Standard Offer electric service required for irrigation pumping or for water utilities for pumping potable water to serve the citizens of a city, town, or unincorporated community. Service must be supplied at one point of delivery and measured through one meter. Direct Access customers are not eligible for service under this schedule.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplementary, residential or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site.

## RATES

The bill shall be computed at the following rates or minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

| | | |
|---|---|---|
| Basic Service Charge: | $0.575 | per day, plus |
| Demand Charge: | $1.80 | per kW, plus |
| Energy Charge: | $0.06911 | per kWh for the first 275 kWh per kW, plus |
| | $0.05562 | per kWh for all additional kWh |

### OPTIONAL TIME-OF-WEEK PROVISION

#### AVAILABILITY

The Time-Of-Week option is available to all customers eligible for Rate Schedule E-221. The customer must enter into an Electric Supply Agreement with the Company stating the customer's assigned Control Period. The type of equipment required to provide and measure time-of-week service is non-standard; therefore availability is limited and the Company cannot guarantee installation of the equipment within any specific time.

RATES (cont)

OPTIONAL TIME-OF-WEEK PROVISIONS (cont)

CONTROL PERIOD

The Control Period is the thirteen (13) hour period from 9 a.m. to 10 p.m. for one day during the week (Monday through Friday). The specific day of the Control Period will be mutually agreed upon by the Company and the customer and will be set forth in the Electric Supply Agreement.

RATE

The bill for customers on the Time-Of-Week option will be adjusted in the following manner:

| When measured kWh during the specified Control Period is: | The following will be applied to the bill (before any adjustments, taxes or assessments) |
|---|---|
| 1. 2 kWh per kW or less | ($0.00739) per kWh for all kWh |
| 2. Greater than 2 kWh per kW but less than or equal to 8 kWh per kW | ($0.00000) |
| 3. Greater than 8 kWh per KW | $0.00370 per kWh for all kWh |

DETERMINATION OF KW

The kW charges billed in this schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the Company's meter, or at the Company's option, by test.

MINIMUM

The bill for service under this rate schedule will not be less than $0.575 per day plus $1.80 for each kW of the highest kW established during the 12 months ending with the current month, or the minimum kW specified in the Electric Service Agreement, whichever is greater. However, such monthly minimum charge shall not be more than an amount sufficient to make the total charges for such 12 months equal to $21.60 for each of such highest kW plus $210.00, but in no instance more than the monthly minimum amount as computed above.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for customers receiving service under this rate schedule will be one (1) year or longer. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-221-8T
# CLASSIFIED SERVICE
# WATER PUMPING SERVICE – TIME-OF-USE

## AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate schedule is applicable to all Standard Offer electric service required for irrigation pumping or for water utilities for pumping potable water to serve the citizens of a city, town, or unincorporated community. Service must be supplied at one point of delivery and measured through one meter. Direct Access customers are not eligible for service under this schedule.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplementary, residential or resale service.

## TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site.

## RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

### RATE

| | | |
|---|---|---|
| Basic Service Charge: | $0.851 | per day, plus |
| Demand Charge: | $4.21 | per On-Peak kW, plus |
| | $2.51 | per Off-Peak kW, plus |
| Energy Charge: | $0.08492 | per kWh during On-Peak hours, plus |
| | $0.04567 | per kWh during Off-Peak hours |

### TIME PERIODS

For the purpose of this rate schedule, the On-Peak time period is a consecutive eight (8) hour period between 9 a.m. and 10 p.m. every day of the week. The specific On-Peak period will be mutually agreed upon by the Company and the customer and will be set forth in an Electric Supply Agreement. All hours not included in the specified On-Peak period are designated as Off-Peak hours.

Mountain Standard Time shall be used in the application of this rate schedule.

RATES (cont)

DETERMINATION OF KW

The kW charges billed in this schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month, for both On-Peak and Off-Peak periods, as determined by readings of the Company's meter, or at the Company's option, by test.

MINIMUM

The bill for service under this rate schedule will not be less than $.851 per day plus $2.51 for each kW of the highest kW established on or off peak during the 12 months ending with the current month, or the minimum kW specified in the Electric Service Agreement, whichever is greater. However, such monthly minimum charge shall not be more than an amount sufficient to make the total charges for such 12 months equal to $30.12 for each of such highest kW plus $310.44, but in no instance more than the monthly minimum amount as computed above.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to a Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for customers receiving service under this rate schedule will be one (1) year or longer. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer.

TERMS & CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE E-249
# CLASSIFIED SERVICE – SHARE THE LIGHT
# CAMP VERDE STREET LIGHTING

AVAILABILITY

In the Town of Camp Verde.

APPLICATION

To electric service billed under the applicable Street Lighting Schedule E-58.

All provisions of the Street Lighting Schedule E-58 will apply except as specifically modified herein.

Service under this rate schedule is limited to those streetlights installed prior to April 8, 1980. The Company is not obligated to install new light fixtures, poles or distribution circuits, but will continue to maintain and operate those installed prior to April 8, 1980 only while maintenance and replacement materials are available from Company stock or until this rate schedule is cancelled, whichever comes first, provided, however, under no circumstances shall poles be relocated. Interfering poles shall only be removed. The Company is authorized to collect from the sponsoring entity, any and all unpaid bills for street lighting service.

THE STREET LIGHTING SYSTEM

The Company has installed, at its own expense, a street lighting system as prescribed by the Camp Verde Lions Club.

The Company agrees to submit all requests for an increase or decrease in number or size of street lights, change in location, change in assessment or like matters regarding Camp Verde street lights, to the Camp Verde Lions Club for approval. After recommendation by the Camp Verde Lions Club, such requests are to be submitted to the Arizona Corporation Commission for final approval before any action is taken by the Company.

RATES

For purposes of assessment, each Camp Verde commercial customer (not classified as rural) is to be considered equivalent to six Camp Verde residential customers. Camp Verde customers to be assessed for street lighting shall include all commercial and residential customers of the Arizona Public Service Company located within, and immediately adjacent thereto, the boundaries of the Military Reserve Addition, Blocks 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 16, 17, 18, and 19, of Camp Verde Townsite. Customers taking electric service outside of these districts shall be classified as Rural, and not subject to assessment for street lighting.

The monthly charge for street lighting is to be divided by a figure equal to the total number of residential customers for the month, plus six times the number of commercial customers. This assessment is to be adjusted to the nearest cent. Each Camp Verde residential customer is to be assessed the amount of the individual assessment as determined by the above method. Each Camp Verde commercial customer is to be assessed six times the amount of the individual assessment as determined by the above method. The above assessment will be added to the customer's bill for service.

RATES (cont)

Only one meter in each business house is to be counted as a commercial customer and one meter in each residence as a residential customer, regardless of the number of meters installed on the customer's premises to serve any such commercial or residential customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE EPR-2
# CLASSIFIED SERVICE
# PURCHASE RATES FOR QUALIFIED FACILITIES UNDER 100 kW FOR PARTIAL REQUIREMENTS

## AVAILABILITY

In all territory served by Company.

## APPLICATION

To all cogeneration and small power production facilities 100 kW or less where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to qualifying facilities (QF's) electing to configure their systems as to require only partial requirements or interruptible service from the Company in order to meet their electric requirements.

## TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises). The qualifying facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the QF will be responsible for all incremental costs incurred to accommodate such an arrangement.

## PAYMENT FOR PURCHASES FROM AND SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the Customer in order to meet its supplemental or interruptible electric requirements will be priced at the applicable retail rate or rates.

The Company will pay the Customer for any energy purchased as calculated on the standard purchase rate (see below).

## PURCHASE RATE

Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company:

| | Cents per kWh | | | |
|---|---|---|---|---|
| | Non-Firm Power | | Firm Power | |
| | On-Peak[1/] | Off-Peak[2/] | On-Peak[1/] | Off-Peak[2/] |
| Summer Billing Cycles (June - October) | 3.551 | 2.257 | 5.433 | 3.453 |
| Winter Billing Cycles (November - May) | 2.552 | 1.871 | 3.904 | 2.862 |

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays

[2/] Off-Peak Periods: All other hours

PURCHASE RATE (cont)

These rates are based on the Company's estimated avoided energy costs and will be updated annually to reflect changes in the Company's fuel costs.

SERVICE CHARGE

The monthly service charge shall be determined in accordance with the type of customer service characteristics as set forth below:

| | Monthly Charge |
|---|---|
| Single Phase Service: | |
| 0-200 amp service | $ 7.34 |
| Three Phase Service: | |
| 0-200 amp service | $ 8.87 |
| 201-400 amp service | $18.31 |

CONTRACT PERIOD

As provided for in the Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service - A QF's system configuration whereby the output from its electric generator(s) first go to supply its own electric requirements with any excess energy (over and above its own requirements at the time) then being sold to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by the QF's own generation facilities). This also may be referred to as the "parallel mode" of operation.

2. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

   - Interruptible Power - Electric energy or capacity supplied by the Company subject to interruption by the Company under specified conditions and under agreed upon lead time requirements.

3. Non-Firm Power - Electric power which is supplied by the power producer at the producer's option, where no firm guarantee is provided, and the power can be interrupted by the power producer at any time.

4. Firm Power - Power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

DEFINITIONS (cont)

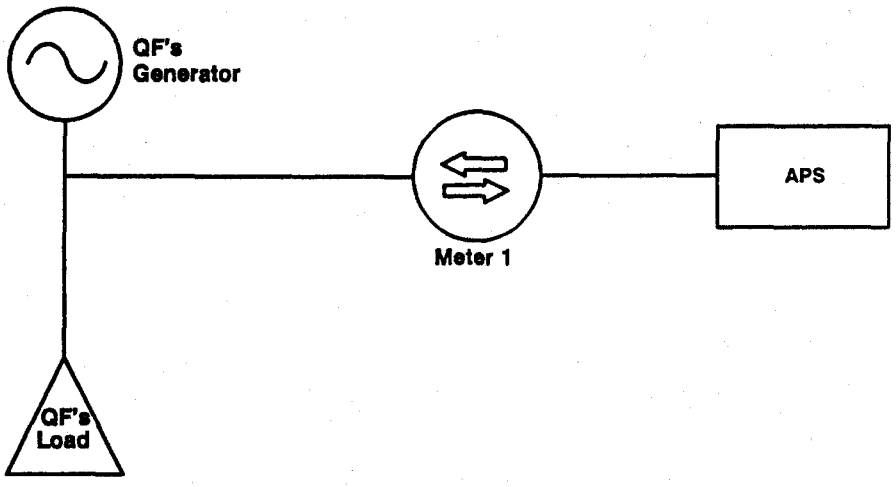
5. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, or as it may be amended or modified from time to time by any supplemental or special Terms and Conditions pursuant to Customer's Purchase Agreement with the Company.

Customer and Company will share in the cost of the bi-directional meter used to record sales to the Customer and purchases from the Customer. Company shall be responsible for all costs up to and equal to the installed cost of a residential time-of-use meter, and Customer shall be responsible for the difference between the installed cost of the bi-directional meter compared to a standard residential time-of-use meter. Customer shall have the option to pay the incremental metering costs initially or in monthly installements over a five year time period.

METERING CONFIGURATION



# RATE SCHEDULE EPR-3
# CLASSIFIED SERVICE
# PURCHASE RATES FOR QUALIFIED FACILITIES
# 10 kW OR LESS FOR PARTIAL REQUIREMENTS

## AVAILABILITY

In all territory served by Company.

## APPLICATION

To all small power production facilities with a nameplate rating of 10 kW or less utilizing solar/photovoltaic technology where the customer's generator(s) and load are located at the same premise and meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to qualifying facilities (QF's) either: a) operating in the simultaneous buy/sell mode (whereby all the QF's generation output is fed directly into the Company's system and all of the QF's electric requirements are met by sales from the Company) or; b) QF's electing to configure their systems as to require only partial requirements or interruptible service from the company in order to meet their electric requirements.

Applicable only to those customers being served on the Company's Rate Schedule EPR-3 prior to July 1, 1996.

## TYPE OF SERVICE

Electric sales to the Company must be single phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises). The qualifying facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the Customer will be responsible for all incremental costs incurred by APS to accommodate such an arrangement.

## BILLING OPTIONS FOR PURCHASES FROM AND SALES TO THE CUSTOMER

The Customer will have the option of choosing either of the following two methods for determining the bill for purchases and sales:

A. Net Bill Method:

The energy (kWh's) sold to the Company shall be subtracted from the energy purchased from the Company. If the difference is positive, the net energy received from the Company will be priced at the applicable standard retail rate under which the Customer would otherwise purchase its full requirements service. If the difference is negative, the net energy delivered to the Company will be priced at the Monthly Purchase Rate shown below.

B. Separate Bill Method:

All sales and purchases shall each be treated separately with sales to the Customer billed on the applicable standard retail rate for full requirements service, and purchases of energy from the Customer's QF priced at the Monthly Purchase Rate shown below.

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director of Pricing
Original Effective Date: February 4, 1993

A.C.C. No. XXXX
Canceling A.C.C. No. 5518
Rate Schedule EPR-3
Revision No. 9
Effective: XXXXXX

Page 1 of 5

MONTHLY PURCHASE RATE

Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company under either Billing Option A or Option B:

| | Cents per kWh Non-Firm Power On-Peak[1/] | Off-Peak[2/] | Firm Power On-Peak[1/] | Off-Peak[2/] |
|---|---|---|---|---|
| Summer Billing Cycles (June - October) | 3.351 | 2.257 | 5.433 | 3.453 |
| Winter Billing Cycles (November - May) | 2.552 | 1.871 | 3.904 | 2.862 |

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually to reflect changes in the Company's fuel costs.

METERING

See pages 3 and 4 Metering Configurations & Options outlining the metering options available to solar/photovoltaic QF Customers electing the simultaneous buy/sell mode or the parallel mode of operation.

CONTRACT PERIOD

As provided for in the Purchase Agreement.

DEFINITIONS

1. Full Requirements Service - Any instance whereby the Company provides all the electric requirements of a Customer.

2. Partial Requirements Service - A QF's system configuration whereby the output from its electric generator(s) first go to supply its own electric requirements with any excess energy (over and above its own requirements at the time) then being sold to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by the QF's own-generation facilities). This also may be referred to as the "parallel mode" of operation.

3. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

   Interruptible Power - Electric energy or capacity supplied by the Company subject to interruption by the Company under specified conditions and under agreed upon lead time requirements.

FROZEN

DEFINITIONS(cont)

3. Non-Firm Power - Electric power which is supplied by the power producer at the producer's option, where no firm guarantee is provided, and the power can be interrupted by the power producer at any time.

4. Firm Power - Power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

5. Net Energy - The total kilowatthours (kWh's) sold to the Customer by the Company less the total kWh's purchased by the Company from the Customer's QF. "Net energy" applies only to those QF's operating in the simultaneous buy/sell mode.

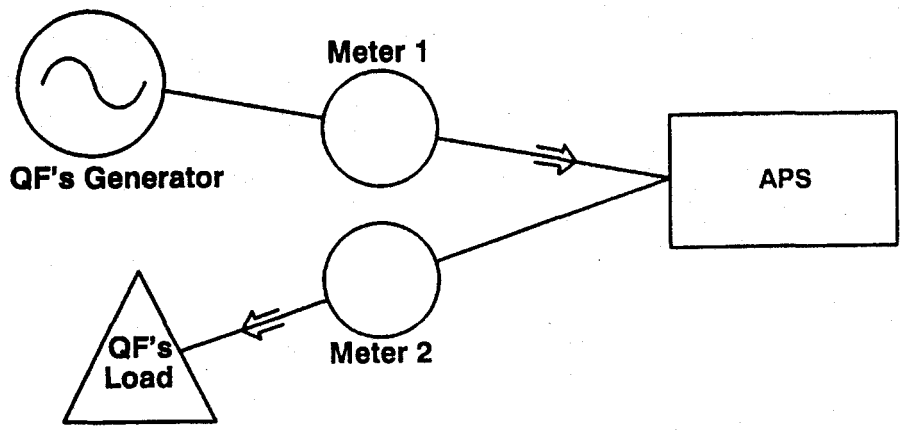
6. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

FROZEN

METERING CONFIGURATIONS & OPTIONS
FOR SOLAR/PHOTOVOLTAIC QF APPLICATIONS 10 KW OR LESS
(Simultaneous Buy/Sell Mode)



METERING OPTIONS

| | Type of Meter (Meter 1) | Type of Meter (Meter 2) |
|---|---|---|
| Qualifying Facilities Utilizing Solar/Photovoltaic Technology 10 kW or less: | | |
| f on an Energy Only (kWh) Type Rate* | TOU[a/] | kWh[b/] |
| f on a Time-of-Use Type Rate* | TOU[c/] | TOU[d/] |

* Refers to the Customer's otherwise applicable standard retail rate for firm purchases from the Company.

a/ A Time-of-use (TOU) meter that registers kWh's only during peak and off-peak periods as specified in the "Monthly Purchase Rate" section of this rate schedule.

b/ A non-timed watthour meter that registers kWh's only.

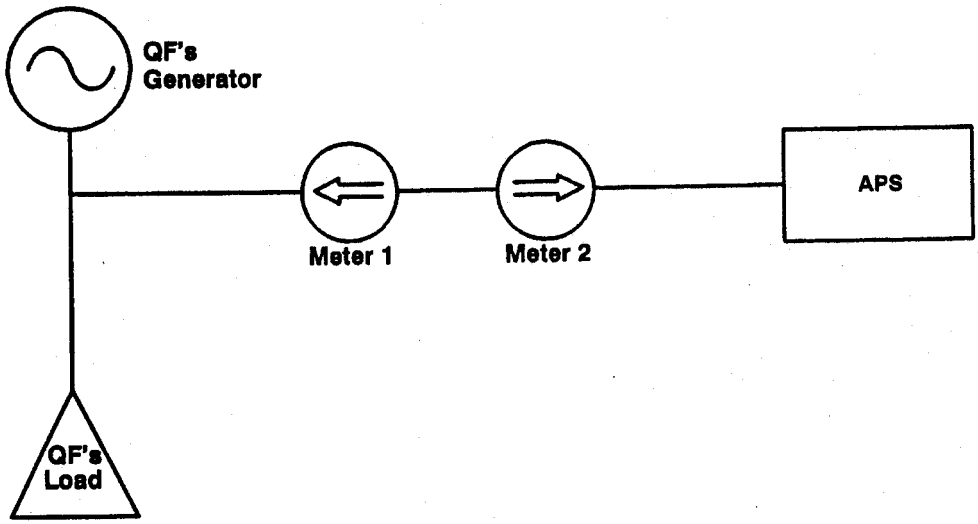
c/ A TOU meter that registers kWh's only during peak and off-peak periods concurrent with those periods used in measuring energy for billing purposes by Meter 2.

d/ As per applicable rate schedule.

NOTE: APS shall be responsible for providing all required meters for the Simultaneous Buy/Sell Mode under the EPR-3 Metering Configuration.

FROZEN

METERING CONFIGURATIONS & OPTIONS
FOR SOLAR/PHOTOVOLTAIC QF APPLICATIONS 10 KW OR LESS
(Parallel Mode of Operation)



METERING OPTIONS

| | Type of Meter (Meter 1) | Type of Meter (Meter 2) |
|---|---|---|
| Qualifying Facilities Utilizing Solar/Photovoltaic Technology 10 kW or less: | | |
| If on an Energy Only (kWh) Type Rate* | kWh[a/] | TOU[b/] |
| If on a Time-of-Use Type Rate* | TOU[c/] | TOU[d/] |

*Refers to the Customer's otherwise applicable standard retail rate for firm purchases from the Company.

a/ A non-timed watthour meter that registers kWh's only.

b/ A Time-of-use (TOU) meter that registers kWh's only during peak and off-peak periods as specified in the "Monthly Purchase Rate" section of this rate schedule.

c/ As per applicable rate schedule.

NOTE: APS shall be responsible for providing all required meters for the parallel mode of operation under the EPR-3 Metering Configuration.

FROZEN

# RATE SCHEDULE EPR-4
# CLASSIFIED SERVICE
# PURCHASE RATES FOR RENEWABLE QUALIFYING FACILITES 10 kW OR LESS FOR PARTIAL REQUIREMENTS

## AVAILABILITY

In all territory served by Company.

## APPLICATION

To all small power production facilities with a nameplate rating of 10 kW or less utilizing renewable resource technologies where the customer's generator(s) and load are located at the same premise and meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to qualifying facilities (QF's) electing to configure their systems as to require only partial requirements or interruptible service from the Company in order to meet their electric requirements.

## TYPE OF SERVICE

Electric sales to the Company must be single phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises). The qualifying facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the Customer will be responsible for all incremental costs incurred by APS to accommodate such an arrangement.

## PAYMENT FOR PURCHASES FROM AND SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the Customer in order to meet its supplemental or interruptible electric requirements will be priced at the applicable retail rate or rates.

The Company will pay the Customer for any energy purchased as calculated on the standard purchase rate (see below).

## PURCHASE RATE

Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company:

| | Cents per kWh | | | |
|---|---|---|---|---|
| | Non-Firm Power | | Firm Power | |
| | On-Peak[1/] | Off-Peak[2/] | On-Peak[1/] | Off-Peak[2/] |
| Summer Billing Cycles (June - October) | 3.351 | 2.257 | 5.433 | 3.453 |
| Winter Billing Cycles (November - May) | 2.552 | 1.871 | 3.904 | 2.862 |

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually to reflect changes in the Company's fuel costs.

CONTRACT PERIOD

As provided for in the Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service - A QF's system configuration whereby the output from its electric generator(s) first go to supply its own electric requirements with any excess energy (over and above its own requirements at the time) then being sold to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by the QF's own-generation facilities). This also may be referred to as the "parallel mode" of operation.

2. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

   - Interruptible Power - Electric energy or capacity supplied by the Company subject to interruption by the Company under specified conditions and under agreed upon lead time requirements (Non-Firm Power).

3. Non-Firm Power - Electric power which is supplied by the power producer at the producer's option, where no firm guarantee is provided, and the power can be interrupted by the power producer at any time.

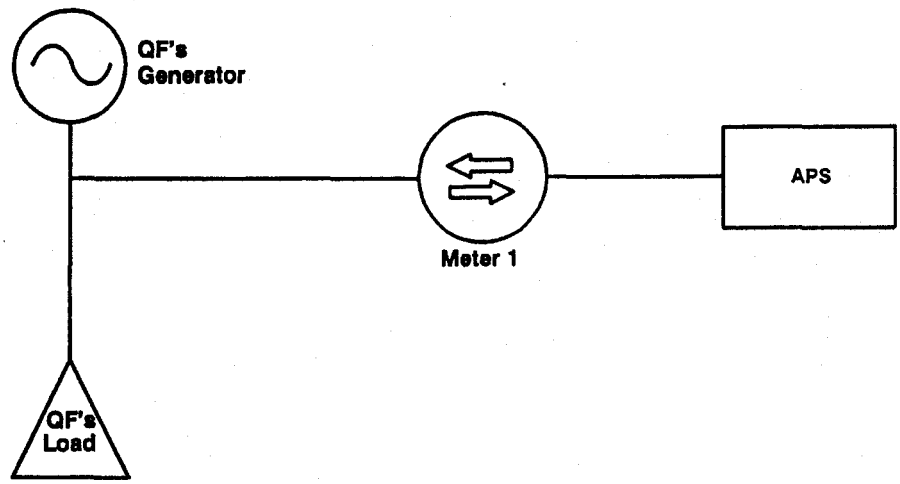
4. Firm Power - Power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

5. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

METERING CONFIGURATION



# RATE SCHEDULE EQF-M
# CLASSIFIED SERVICE
# SCHEDULED MAINTENANCE SERVICE
# FOR QUALIFIED FACILITIES

## AVAILABILITY

This rate scheulde is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage can be made available to the site to be served and when all applicable provisions listed in the Special Provisions section of this schedule have been met.

## APPLICATION

This rate schedule is applicable only to qualified cogeneration and small power production facilities 100 kW or less that meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities capable of producing firm power, where the facility's generator(s) and load are located at the same site. To electric service for agreed kW quantities of contracted maintenance capacity, taken during scheduled periods, to a customer who is not taking full requirements service from the Company but nevertheless desires a permanent electric connection with the Company as a maintenance power source.

## RATE

The applicable rate for service taken under this schedule shall be ECT-1R, except that any provisions in the rate that may prohibit such type service as specified under this schedule is hereby waived, and the interval of integration for the determination of kW capacity for billing purposes (e.g., 15 minutes, 1 hour, etc.) shall be the same as that under the customer's normally applicable rate for firm service. All other provisions of the rate shall be effective.

## SPECIAL PROVISIONS

1. Agreement For Service: A contract for a minimum period of one year is required for service under this schedule. All provisions outlining service under this schedule shall be contained in the Agreement For Service.

2. KW QF Contract Capacity: The levels of contract capacity for both firm service (if applicable) and maintenance service shall be specified in the Agreement For Service. Unless otherwise agreed to by the Company, the contract capacity for maintenance power shall not exceed the aggregate nameplate rating(s) of the customer's generating source.

   Customer will be permitted to increase contracted firm power and/or maintenance power amounts upon 30 days written notice to the Company, provided, however, a new Agreement For Service incorporating these changes is signed for a period lasting no less than one year. Except as provided otherwise in the following paragraph, contracted maintenance capacity amounts shall not be changed unless actual changes in the capacity of the customer's generating facilities have been made. Decreases in a customer's contracted firm capacity amount will not be allowed until expiration of the contract period.

   If customer exceeds contracted amount for maintenance capacity, customer's firm contract capacity will be increased by said excess. If customer is not presently receiving firm service, such service shall be instituted for an amount no less than that which may have exceeded the contracted maintenance capacity level stated in the Agreement For Service, under the appropriate rate for such service.

3. Firm Power: For purposes of this rate, firm power shall be defined to be power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement For Service from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

SPECIAL PROVISIONS (cont)

4. Scheduled Maintenance Periods: For purposes of this rate, scheduled maintenance periods shall be defined as those periods specified by the Company during which customer can take electric power under this schedule. Currently, the designated periods during which the customer may take maintenance power are:

| | |
|---|---|
| October 1 - January 31 | At all times |
| February 1 - May 31 | Only between the hours of 10:00 p.m. to 7:00 a.m. |
| June 1 - September 30 | No maintenance shall be permitted at any time |

The use of maintenance power during periods other than those specified above is prohibited. The Company reserves the right to periodically change these periods from time to time as conditions warrant.

Optional Procedure: Customer may take power in order to perform maintenance on his facility provided the time and duration of such outages are scheduled in advance with the concurrence of the Company. Reasonable periods will be allowed for major equipment repairs or overhaul, not to exceed four weeks in duration, provided such periods do not exceed one per 12 month period. The Company will make every effort possible to accommodate the customer's requirements; however, the Company's operational circumstances will determine when such scheduling shall be permitted.

5. Metering Facilities: Service under this rate schedule will be provided on a time-of-day basis requiring appropriate metering equipment. Customer shall submit requirements for service to the Company so that adequate service and metering facilities can be determined in order to meet the needs of the customer's facility. Said facilities shall be specified in the Agreement For Service.

6. Use of Maintenance Power During Unauthorized Periods: Customer shall not be permitted to utilize maintenance power at any time other than that specifically authorized by the Company as outlined in Special Provision 4 of this schedule. Unauthorized use of maintenance power shall be treated in the following manner:

   a) For the first breach of this provision within a 12 month period of time, the customer shall receive a written notice thereof from the Company.

   b) In the event of a second breach of this provision during the same 12 month period, in addition to the payments calculated under this rate schedule, customer shall be required to pay:

      1) 50% of the capacity charge of the applicable rate for standby service for qualifying cogeneration or small power production facilities multiplied by customer's contracted amount for maintenance capacity multiplied by the number of months previously receiving service on this schedule (however, not to exceed 12); and

      2) Customer shall be placed on the applicable standby rate. Customer will be eligible again for the maintenance rate after a 12 month period during which time it has been demonstrated that customer's facility can be operated within the constraints of the scheduled maintenance periods.

7. Charge for Facilities: The Company reserves the right to establish a minimum charge in order to recover the costs of facilities required to serve such load. Said charge shall be specified in the Agreement For Service.

SPECIAL PROVISIONS (cont)

8. Reconnect Charge: If the customer terminates service under this schedule and elects to re-initiate service at the same premises within a 12 month period of time, the reconnect charge shall be equal to the minimum charge the customer would have otherwise been required to pay had service not been terminated.

9. Conflicts: In case of an inconsistency between any provision of the Agreement For Service, this rate schedule and/or the Terms and Conditions for the Sale of Electric & Gas Service, the inconsistency shall be resolved by giving priority to the Agreement For Service, the rate and then the Terms and Conditions in said respective order. Any provisions in the customer's normally applicable rate for firm service that prohibits partial requirements type service(s) is hereby waived.

10. Refusal to Serve Maintenance Power: The Company reserves the right to refuse to provide maintenance service to a customer's facility during such periods of time when supplying such power may contribute to a system emergency. In addition, the Company reserves the right to refuse maintenance service to cogeneration or small power production facilities when, in the Company's opinion, service to such a facility may constitute a hazard to the Company's or other customer's facilities.

TIME PERIODS

Mountain Standard Time shall be used in the application of this rate schedule. In addition, to prevent radical changes in the system loads, the beginning and ending hours for individual customers may be varied by up to one hour (total hours in each time period to remain unchanged) and because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE EQF-S
# CLASSIFIED SERVICE
# STANDBY ELECTRIC SERVICE
# FOR QUALIFIED FACILITIES

## AVAILABILITY

This rate schedule is available in all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served and when all applicable provisions listed in the Special Provisions section of this schedule have been met.

## APPLICATION

This rate schedule is applicable only to qualified cogeneration and small power production facilities 100 kW or less that meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities capable of producing firm power, where the facility's generator(s) and load are located at the same premises. To electric service for agreed kW quantities of contracted standby capacity to a customer who is not taking full requirements service from the Company but nevertheless desires a permanent electric connection with the Company as a standby power source.

## RATE

The bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A) The bill for standby service taken as computed under the ECT-1R rate schedule; or

B) Customer's contract standby capacity amount multiplied by 1/2 the on-peak capacity charge in the ECT-1R rate schedule; plus the Basic Service Charge in ECT-1R.

Any provisions in the ECT-1R rate that may prohibit such type service as specified under this schedule is hereby waived. The interval of integration for the determination of kW capacity for billing purposes (e.g., 15 minutes, 1 hour, etc.) shall be the same as that under the customer's normally applicable rate for firm service. All other provisions of the rate shall be effective.

## SPECIAL PROVISIONS

1. Agreement For Service: A contract for a minimum period of one year is required for service under this schedule. All provisions outlining service under this schedule shall be contained in the Agreement For Service.

2. KW QF Contract Capacity: The levels of contract capacity for both firm service (if applicable) and standby service shall be specified in the Agreement For Service. Unless otherwise agreed to by the Company, the contract capacity for standby power shall not exceed the aggregate nameplate rating(s) of the customer's generating source.

   Customer will be permitted to increase contracted firm power and/or standby power amounts upon 30 days written notice to the Company, provided, however, a new Agreement For Service incorporating these changes is signed for a period lasting no less than one year. Except as provided otherwise in the following paragraph, contracted standby capacity amounts shall not be changed unless actual changes in the capacity of the customer's generating facilities have been made. Decreases in a customer's contracted firm capacity amount will not be allowed until expiration of the contract period.

SPECIAL PROVISIONS (cont)

2. (cont) If customer exceeds contracted amount for standby capacity, customer's firm contract capacity will be increased by said excess. If customer is not presently receiving firm service, such service shall be instituted, for an amount no less than that which may have exceeded the contracted standby capacity level stated in the Agreement For Service, under the appropriate rate for such service.

3. Firm Power: For purposes of this rate, firm power shall be defined to be power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement For Service from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

4. Standby Power: For purposes of this rate, standby power shall be defined to be electric capacity and associated energy, in excess of customer's contracted capacity for firm service, supplied by the Company to replace power ordinarily generated by the customer's generation facility during scheduled or unscheduled outages of said facility.

5. Metering Facilities: Service under this rate schedule will be provided on a time-of-day basis requiring appropriate metering equipment. Customer shall submit requirements for service to the Company so that adequate service and metering facilities can be determined in order to meet the needs of the customer's facility. Said facilities shall be specified in the Agreement For Service.

6. Charge for Facilities: The Company reserves the right to establish a minimum charge in order to recover the costs of facilities required to serve such load. Said charge shall be specified in the Agreement For Service.

7. Reconnect Charge: If the customer terminates service under this schedule and elects to re-initiate service at the same premises within a 12 month period of time, the reconnect charge shall be equal to the minimum charge the customer would have otherwise been required to pay had service not been terminated.

8. Conflicts: In case of an inconsistency between any provision of the Agreement For Service, this rate schedule and/or the Terms and Conditions for the Sale of Electric & Gas Service, the inconsistency shall be resolved by giving priority to the Agreement For Service, the rate and then the Terms and Conditions in said respective order. Any provisions in the customer's normally applicable rate for firm service that prohibits partial requirements type service(s) is hereby waived.

9. Refusal to Serve Standby Power: The Company reserves the right to refuse to provide standby service to a customer's facility during such periods of time when supplying such power may contribute to a system emergency. In addition, the Company reserves the right to refuse standby service to cogeneration or small power production facilities when, in the Company's opinion, service to such a facility may constitute a hazard to the Company's or other customer's facilities.

TIME PERIODS

Mountain Standard Time shall be used in the application of this rate schedule. In addition, to prevent radical changes in the system loads, the beginning and ending hours for individual customers may be varied by up to one hour (total hours in each time period to remain unchanged) and because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE SOLAR-1
# CLASSIFIED SERVICE
# PHOTOVOLTAIC SERVICE PILOT PROGRAM

FROZEN

## AVAILABILITY

Company will offer power generated by a Company owned and maintained photovoltaic system to customers who cannot be economically connected by extension of Company distribution system. Available within Company's service territory to customers who 1) are requesting new (not previously existing) service and 2) are located in areas where a line extension for regular electric service is less economical than the photovoltaic system as determined by the ACC "Staff Guidelines on Photovoltaics Versus Line Extensions".

Customer's system must be in a location that is reasonably accessible by standard Company vehicles. It will be located on the customer's property. If the system is not installed at the customer's permanent residence (that at which customer resides for at least six months a year) the customer will be required to post a five year surety bond for the amount of the photovoltaic system Net Installed Cost.

This pilot program is only available until January 1, 1996 or until the total Company investment in the Photovoltaic Service Pilot Program reaches $250,000.

## APPLICATION

Company has the sole right to determine the customer's eligibility for service under this schedule. Service under this schedule is limited to photovoltaics of 0.2 kW or greater having a Net Installed Cost of more than $1,500 but less than $50,000.

Applicable only to those customers being served on the Company's Rate Schedule Solar-1 prior to August 1, 1996.

## TYPE OF SERVICE

The system typically will include a photovoltaic module array, the module array mounting structure, the control structure, the control equipment, any necessary wiring, batteries, and any other equipment necessary to provide service at a mutually agreed upon point of delivery. Company will own, maintain, and make any necessary repairs to the photovoltaic system. If the system is damaged or in need of repairs, customer shall notify Company promptly.

This service is a substitute for and is in lieu of the customer being connected to the Company's electric distribution system. Any back-up, supplemental, or alternate power generation shall be the customer's responsibility, and Company assumes no obligation to provide or arrange for such back-up, supplemental or alternative power. Any back-up power equipment must meet Company technical specifications, and be connected to the photovoltaic system only at a Company designated point.

## INITIAL FEE

An Initial Fee equal to five percent of the estimated Total Installed Cost of the photovoltaic system is required from the customer at the time the Photovoltaic Facilities Agreement is executed. The Initial Fee is a contribution in-aid-of-construction and will be deducted from the Total Installed Cost of the photovoltaic array and system wiring to yield the Net Installed Cost. The Initial Fee shall be non-refundable unless Company determines that it will not install the photovoltaic system.

RATE

The total bill is based on the type of system installed and the rate formula specified below. The exact charge will be specified in the Photovoltaic Facilities Agreement. Since each system is designed to meet the customer's specific needs, the rate will vary based on the following formula:

$20.00 monthly service fee, plus

A maximum of 1.6 percent times the portion of the Net Installed Cost of the photovoltaic system parts with a life expectancy of more than 10 years, such as the photovoltaic Array, but not less than marginal cost,

plus

3.1 percent times the portion of the Net Installed Cost of the photovoltaic system parts with a life expectancy of 10 years or less, such as inverter and batteries,

plus

any applicable sales tax and regulatory assessments.

TERMINATION OF SERVICE

Upon discontinuance of the use of any photovoltaic facilities due to termination of service, termination of the Photovoltaic Facilities Agreement, or otherwise:

a) For the purposes of this initial and only pilot program the customer has the option to terminate without the facility termination charge as described below, section (b), when the Photovoltaic Facilities Agreement expires and customer has paid to Company all other monies to which company may be legally entitled.

b) Customer shall pay to Company on demand (in addition to all other monies to which company may be legally entitled by virtue of such termination) a facility termination charge defined as the Net Installed Cost, plus the removal cost less the market salvage value for the photovoltaic facilities to be removed.

c) Upon termination of service, either by Company or customer, customer will have the option to purchase the photovoltaic facilities based on Company's Net Installed Cost less accumulated straight-line depreciation.

SYSTEM MODIFICATIONS

Company will reasonably respond to customer requests for improvement to the performance of the photovoltaic system. However, Company has the sole right to determine if and when a modification to the existing system shall be made and such modification will be at the customer's expense by adjusting the monthly fee. If such improvements cost less than $1000, then no deposit is required. For improvements greater than $1000, an initial fee equal to 5 percent of the total modification cost shall be required prior to installation. The initial fee is non-refundable unless Company determines that the modification is not warranted. If the total modification costs exceed one half of the total installed cost or $5000, a new Photovoltaic Facilities Agreement shall be required. Total modification cost will include the cost of all modifications installed in the current fiscal year.

SYSTEM MODIFICATIONS (cont)

Company shall notify the customer of any modifications or improvements to the system by providing the Customer a restated investment/monthly billing statement. Company shall adjust the monthly bill accordingly. The Net Modification Cost will be equal to the total modification cost less the 5% Initial Fee. The Net Modification Cost will be added to the existing Net Installed Cost to yield a revised Net Installed Cost that will henceforth be used to compute the bill.

CONTRACT PERIOD

As provided for in the Photovoltaic Facilities Agreement.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE SOLAR-2
# CLASSIFIED SERVICE
# INDIVIDUAL SOLAR ELECTRIC SERVICE

## AVAILABILITY

Available within Company's service territory to customers who are requesting new service requiring a new line extension and are located in areas where a line extension for regular electric service is less economical than Individual Solar Electric Service. Company has the right to refuse service at unsecured locations which in the company's opinion is a high risk area for vandalism, theft, or other damage.

Customer's system must be in a location that is determined by the Company to be reasonably accessible by standard Company vehicles. It will be located on the customer's property. If the system is not installed at the customer's permanent residence (that at which customer resides for at least six months a year) the customer may be required to post security as determined by the Company for the amount of the Solar Electric system Net Installed Cost.

This service is only available until the Company investment in the Individual Solar Electric Service reaches the ACC approved funding limit.

## APPLICATION

Company has the sole right to determine the customer's eligibility for service under this schedule. Service under this schedule is limited to solar electric systems with name plate ratings of 200 watts or greater and having a Net Installed Cost of more than $1,500.

## TYPE OF SERVICE

Company will offer power generated by a Company owned and maintained Solar Electric system for customers who cannot be economically connected by extension of Company distribution system. The system typically will include a photovoltaic module array, the module array mounting structure, the control structure, the control equipment, any necessary wiring, batteries, and any other equipment necessary to provide service that meets all applicable building and safety codes at a mutually agreed upon point of delivery. Company will own, maintain, and make any necessary repairs to the Solar Electric system. If the system is damaged or in need of repairs, customer shall notify Company promptly.

This service is a substitute for and is in lieu of the customer being connected to the Company's electric distribution system. Any back-up, supplemental, or alternate power generation source may be contracted with the Company. Company assumes no obligation to provide or arrange for such back-up, supplemental or alternative power unless it is part of the Solar Electric Service Agreement and not interconnected to the normal Company system. Any back-up power equipment must meet Company technical specifications, and be connected to the Solar Electric system only at a Company designated point.

## INITIAL FEE

An Initial Fee equal to five percent or more of the estimated Total Installed Cost of the Solar Electric system is required from the customer at the time the Contract is executed. The Initial Fee will be deducted from the Total Installed Cost, starting with the system component with the longest life, to yield the Net Installed Cost by system component. The Initial Fee shall be non-refundable unless Company subsequently determines that it will not install the Solar Electric system. Customer has the option to pay a higher initial fee to reduce the net installed cost of the system.

INITIAL FEE (cont)

The minimum Initial Fee is:

| Estimated Total Installed Cost | | Minimum Initial Fee |
|---|---|---|
| Up to | $100,000 | 5% |
| More than | $100,000 | 10% |

RATE

The total monthly bill is based on the type of system installed and the rate formula specified below. The exact charge will be specified in the service agreement entered into between the Company and customer. Since each system is designed to meet the individual customer's specific needs, the rate will vary based on the following formula:

Monthly service fee, dependent on battery type and system size:

| | System Size | |
|---|---|---|
| **Battery** | Up to 2.5 kW | Over 2.5 kW |
| None | $5.00 | $5.00 |
| Sealed | $45.00 | $65.00 |
| Flooded | $65.00 | $85.00 |

plus,

Component Fee which is the summation of the Net Installed Cost by System Component times the appropriate Monthly Percentage. The monthly percentages listed are maximums that can not be reduced below marginal cost:

| System Component | | Straight Line | Monthly |
|---|---|---|---|
| **Type** | **Average Life** | **Depreciation Life** | **Percentage** |
| **Long** | Greater than 13 years | 20 Years | 1.41% |
| **Medium** | Between 7 and 13 years | 10 Years | 1.83% |
| **Short** | Less than 7 years | 5 Years | 2.75% |

plus,

any applicable sales tax and regulatory assessments.

The Company may offer an accelerated payment schedule to accelerate equipment depreciation allowing the customer to purchase the system for a lower book value.

TERMINATION OF SERVICE

Upon termination of service for any reason other than the Contract terms:

a) Customer shall pay to Company on demand (in addition to all other monies to which Company may be legally entitled by virtue of such termination) a facility termination charge defined as the Net Installed Cost less depreciation (based on customer's payment selection), plus the removal cost less the market salvage value for the Solar Electric facilities to be removed. Market salvage value is defined as new reconstruction cost of the system less depreciation for the same time period as the existing system.

b) Upon termination of service, either by Company or customer, customer will have the option to purchase the Solar Electric facilities based on Company's Net Installed Cost less accumulated depreciation.

If the system is damaged because of vandalism, theft, or abuse Company has the right to terminate service and remove the remaining equipment.

SYSTEM MODIFICATIONS

Company will reasonably respond to customer requests for improvement to the performance of the Solar Electric system. However, Company has the sole right to determine if and when a modification to the existing system shall be made. Such modification will be reflected in customer's monthly bill with a Solar Electric Service Agreement modification. An initial fee of at least 5 percent of the total modification cost shall be required prior to installation. The initial fee is non-refundable unless Company determines that the modification is not warranted.

Company shall adjust the monthly bill by adding the Net Modification Cost to the existing Net Installed Cost to yield a revised Net Installed Cost that will hence forth be used to compute the monthly bill. The Net Modification Cost will be equal to the total modification cost less the Initial Fee for the modification. Company shall provide the customer the revised Net Installed Cost and monthly billing with the revised or amended Solar Electric Service Agreement.

CONTRACT PERIOD

As provided for in the Solar Electric Service Agreement.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# RATE SCHEDULE SP-1
# CLASSIFIED SERVICE
# SOLAR PARTNERS

## AVAILABILITY

This rate schedule is available within the Company's service territory to standard offer residential and business customers on a pre-established service who wish to purchase solar generated electricity for their home and/or business. The total amount sold shall not exceed APS' solar resources. This program may be terminated by the Company at any time without notice.

## APPLICATION

Service under this schedule provides a portion of the customer's regular electric service from solar electric generating systems producing AC electricity and delivered via the Company's electric power grid. All provisions of the customer's current applicable rate schedule will apply in addition to this service.

## TYPE OF SERVICE

The Company will offer power generated by solar electric generating systems through the Company's electric distribution system.

The customer shall contract for a specific number of increments from solar generating facilities. Based upon the average annual output of solar system resources, each increment shall equal approximately 15 kWh/month. The monthly charge is based upon the number of increments and the cost of Solar power in excess of the current rates. The Company may assign limits to the number of kWh increments sold per customer.

## SERVICE CHARGES

The bill, for service under this tariff, shall be $2.64 per month for each 15 kWh monthly increment of solar energy.

## TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

# Adjustments

# RATE SCHEDULE CRCC-1
# COMPETITION RULES COMPLIANCE CHARGE

## APPLICATION

The Competition Rules Compliance Charge (" CRCC") shall apply to all retail electric schedules, excluding those which are for solar service. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

## RATES

The bill shall be calculated at the following rate:

| CRCC | | |
|---|---|---|
| All kWh | $0.000353 | per kWh |

## ADDITIONAL REQUIREMENTS

The A.C.C. authorized in Decision XXXXXX that the amortized amount of $51,433,000 is to be recovered over five years according to the method described in the filed "Competition Rules Compliance Plan for Administration." The CRCC will be canceled once the amortized amount is fully recovered.

# RATE SCHEDULE EPS-1
# ENVIRONMENTAL PORTFOLIO SURCHARGE

## APPLICATION

The Environmental Portfolio Surcharge shall be applied to every metered and/or non metered retail electric service, excluding those services which are for a solar service. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge.

## RATES

The bill shall be calculated at the following rates:

| | | |
|---|---|---|
| All kWh | $ 0.000875 | per kWh |

## SURCHARGE LIMITS

The monthly total of the Environmental Portfolio Surcharge shall not exceed the following limits:

| | | |
|---|---|---|
| Residential Customers | $ 0.35 | per service per month |
| Non-residential Customers | $13.00 | per service per month |
| Non-residential Customers with demand of 3,000 kW or higher per month for three consecutive months | $39.00 | per service per month |

# RATE SCHEDULE PSA-1
# POWER SUPPLY ADJUSTMENT

## APPLICATION

The Power Cost Component Factor (" PCCF") and Amortization Charge shall apply to all Standard Offer retail electric schedules, excluding those which are for solar and E-36 Station Use service. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

## PCCF SEMI-ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include an Average Retail Power Supply Cost (" ARPSC") of $0.023 per kilowatt-hour. In accordance with A.C.C. Decision No. XXXXX, a semi-annual adjustment to the ARPSC will be made through a change in the PCCF that is based upon the rolling twelve-month totals of actual retail power supply costs and retail energy sales. The calculation method is set forth in the filed "Power Supply Adjustment Plan for Administration" (the "Plan"). This Adjustment will be applied to kilowatthour sales under applicable electric schedules. The PCCF cannot exceed the bandwidth limits described in the Plan. The Amortization Charge is not included in the bandwidth calculations.

## BALANCING ACCOUNT

The Company shall establish and maintain a Balancing Account ("Account") for the schedules subject to this provision. Entries shall be made to the Account each month as set forth in the Plan. The Account will include interest applied to over- and under-collected balances based on the non-financial three-month commercial paper rate for each month contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The Plan establishes a maximum amount, or Threshold for the Account balance. If the Account's Threshold is exceeded in a given month then the existing balance will be converted to a kilowatthour charge based on a 12 month amortization period. The result is the Amortization Charge. The Amortization Charge will be charged to the applicable rate schedules until the amortization period is over. The Account's beginning balance for the next month will be set at zero.

## RATES

The bill shall be calculated at the following rate:

| | | |
|---|---|---|
| PCCF | | |
| All kWh | $0.000000 | per kWh |
| Amortization Charge | | |
| All kWh | $0.000000 | per kWh |

## MONTHLY INFORMATIONAL FILINGS

The Company shall make a monthly Power Supply Adjustment information filing with Commission Staff to include any and all information required by A.C.C. Decision No. XXXXX.

ADDITIONAL REQUIREMENTS

A special review is required if the Account exceeds its Threshold amount, an over-collection or under-collection of $50 million. The Company must file an application for an adjustment within forty five (45) days of exceeding the Threshold, or contact the Commission to discuss why an Amortization Charge is not necessary at that time. The Commission, upon review, may authorize the balance to be amortized and converted to an Amortization Charge included as part of the PSA charges for a specified period. If the Threshold is not exceeded but the Company has reason to believe that it can not significantly reduce a large balance in a reasonable amount of time it can file a request with the Commission to adjust the balance through an amortization of all, or part, of the current balance.

DIRECTLY ASSIGNED POWER SUPPLY COSTS

In cases when power supply costs are incurred for a specific customer or group of customers, the customer or group of customers will be charged the identified costs directly. Power supply costs recovered through direct assignments for both existing and returning customers will be excluded from the computation of the above charges applied to other Standard Offer customers.

# RATE SCHEDULE RCDAC-1
# RETURNING CUSTOMER ADJUSTMENT

## APPLICATION

The Returning Customers Direct Assignment Charge (" RCDAC") shall apply to customers or groups of customers over 3 MW's who left Standard Offer retail service or special contract service for competitive generation suppliers and desire to return to Standard Offer service (or customers who were Direct Access customers since origination of service and request Standard Offer service) and for whom APS has not planned resource acquisitions. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

## RATE

The adjustment will be identified in the Electric Service Agreement between the Customer and APS and will be in addition to the Standard Offer service charges.

# RATE SCHEDULE SBAC-1
# SYSTEM BENEFIT ADJUSTMENT CHARGE

APPLICATION

The System Benefit Adjustment Charge ("SBAC") shall be applied monthly to every metered and/or non-metered retail electric service with the exception of solar service. All provisions of the customer's currently applicable rate schedule will apply in addition to this surcharge.

RATE

The bill shall be calculated at the following rate:

| | | | |
|---|---|---|---|
| SBAC | | | |
| | All kWh | $0.000000 | per kWh |

# RATE SCHEDULE TCA-1
# TRANSMISSION COST ADJUSTMENT

## APPLICATION

The Transmission Cost Component Factor ("TCCF") and Amortization Charge shall apply to all Standard Offer retail electric schedules, excluding those which are for solar service. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

## TCCF ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include an Average Transmission and Ancillary Service Cost ("ATASC") of $0.00476 per kilowatt-hour. In accordance with A.C.C. Decision No. XXXXX, an annual adjustment to the ATASC will be made through a change in the TCCF that is based upon the prior year's annual Transmission and Ancillary Service costs and retail energy sales. The calculation method is set forth in the filed "Transmission Cost Adjustment Plan for Administration" (the "Plan"). This Adjustment will be applied to kilowatthour sales under applicable electric schedules.

## BALANCING ACCOUNT

The Company shall establish and maintain a Balancing Account ("Account") for the schedules subject to this provision. Entries shall be made to the Account each month as set forth in the Plan. The Account will include interest applied to over- and under-collected balances based on the non-financial three-month commercial paper rate for each month contained in the Federal Reserve Statistical Release, H-15, or its successor publication. If the Account's balance grows too large then the Company will file a request with the Arizona Corporation Commission to convert the existing balance to a kilowatthour charge based on appropriate amortization period. The result is the Amortization Charge. The Amortization Charge will be charged to the applicable rate schedules until the amortization period is over.

## RATES

The bill shall be calculated at the following rate:

| | | |
|---|---|---|
| TCCF | | |
| All kWh | $0.000000 | per kWh |
| Amortization Charge | | |
| All kWh | $0.000000 | per kWh |

## ANNUAL INFORMATIONAL FILINGS

Annually, the Company shall make a Transmission Cost Adjustment information filing with Commission Staff to include any and all information required by A.C.C. Decision No. XXXXX.

# Service Schedules

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

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

1. General

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

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

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

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

2. Establishment of Service

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

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

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

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

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

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

2.2.1 The customer may additionally be required to pay a trip charge of $17.50 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to meter panel.

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

2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be billed at current hourly rates as determined by Company.

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

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

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

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

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

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

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

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

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

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

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

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

2.5 Establishment of Credit or Security Deposit

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

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

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

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

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

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

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

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

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

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

2.6 Reestablishment of Security Deposit

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

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

2.7 Security Deposits

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

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

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

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

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

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

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

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

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

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

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

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

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

3. Rates

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

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

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

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

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

4. Billing and Collection

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

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

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

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

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

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

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

4.3 Responsibility for Payment of Bills

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

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

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

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

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

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

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

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

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

4.5.1 If a termination is required at the pole, a reconnection charge of $100.00 will be required; if the termination is in underground equipment, the reconnection charge will be $125.00.

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

4.6 On-site Evaluation – Company may require payment of an On-site Evaluation Charge of $90.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of if the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

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

5.2 Responsibility: Use of Service or Apparatus

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

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

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

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

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

5.3 Service Interruptions: Limitations on Liability of Company

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

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

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

5.5 Easements

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

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

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

6. Metering and Metering Equipment

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

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

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

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

6.2 Company Equipment

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

6.2.2 Company will lease lock ring keys to Load Serving ESP'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 ESP's agent, Company may, rather than leasing additional lock ring keys, require the ESP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the Load Serving ESP and/or their authorized agents are:

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

6.2.3 If the Load Serving ESP, 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 $70.00 per site. Company may assess an additional charge, based on the current hourly rate as determined by Company, for joint site meetings that exceed thirty (30) minutes. In the event Company must temporarily replace the ESP's meter and/or associated metering equipment as necessary during emergency situations or to restore power to a customer, the above charges may apply.

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

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

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

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

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

6.4.4 Customer will be billed for the estimated energy and demand that would have registered had the meter been operating properly. Where Company is the MRSP, Company shall, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is $20.00 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 Meter Service Provider (MSP) or (MRSP), and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may obtain the data, or may estimate the billing determinants. The charge for such reread is $20.00 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 $100.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

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

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

7. Termination of Service

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

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

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

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

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

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

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

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

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

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

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

7.2.2 Company has evidence of meter tampering or fraud.

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

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

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

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

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

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

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

# SCHEDULE 2
# TERMS AND CONDITIONS FOR ENERGY PURCHASES FROM QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES

The following TERMS AND CONDITIONS and any changes authorized by law, regulation, rule or order of applicable governmental authority will apply to the purchase of electric energy under the established rate or rates authorized by law and currently applicable at time of purchase; and these TERMS AND CONDITIONS shall be considered a part of all of Company's rate schedules for purchases except where specifically changed by written agreement.

1. DEFINITIONS

1.1 Point Of Interconnection - The point where Company's service conductors are connected to Customer's service conductors.

1.2 Qualifying Facility (QF) - Any cogeneration or small power production facility that meets the criteria for size, fuel use, efficiency, and ownership as promulgated in 18 CFR, Chapter I, Part 292, Subpart B of the Federal Energy Regulatory Commission's Regulations.

1.3 Purchase Agreement - The agreement entered into between Customer and Company detailing the provisions for the purchase of electric energy by Company from Customer's QF, and the sale, if any, of power by Company to Customer.

1.4 Cogeneration Facility - Any facility that sequentially produces electricity, steam or forms of useful energy (e.g., heat) from the same fuel source and which are used for industrial, commercial, heating, or cooling purposes.

1.5 Small Power Production Facility - A facility that uses primarily biomass, waste, or renewable resources, including wind, solar, and water to produce electric power.

2. CUSTOMER'S OBLIGATIONS

2.1 Customer agrees not to commence interconnected operation of its QF with Company's system, until the installation has been inspected by an authorized Company representative and final written approval is received from Company to commence interconnected operation. Customer shall give reasonable notice to Company when initial startup is to begin. Company shall have the right to have a representative present during initial energizing and testing of Customer's system.

2.2 Customer shall own and be fully responsible for the costs of designing, installing, operating and maintaining:

2.2.1 The QF in accordance with the requirements of all applicable electric codes, laws and governmental agencies having jurisdiction.

2.2.2 Control and protective devices to protect its facilities from abnormal operating conditions such as, but not limited to, electrical overloading, abnormal voltages, and fault currents. Such protective devices shall promptly disconnect the QF from Company's system in the event of a power outage on Company's system.

2.2.3 A gang operated load break disconnect switch, capable of being locked in a visibly open position that will completely isolate the QF from Company's system. Such disconnect switch shall be installed in a place easily accessible to Company's personnel. Company shall have the right to lock open the disconnect switch without notice to Customer when interconnected operation of the QF with Company's system could adversely affect Company's system or endanger life or property.

2.2.4 Interconnection facilities on Customer's premises as may be required to deliver power from Customer's QF to Company's system at the agreed Point Of Interconnection.

2.3 Electric sales to Company must be single or three phase, 60 Hertz, at one standard voltage (12,500; 2400/4160; 480; 277/480; 120/240 or 120/208 volts as may be selected by Customer subject to availability at the premises). Customer's facilities shall also maintain a minimum ninety percent (90%) leading to ninety percent (90%) lagging power factor as measured at the Point Of Interconnection.

2.4 The electrical output of Customer's QF shall not contain harmonic content which may cause disturbances on or damage to Company's electrical system, or other party's systems, such as but not limited to communication systems.

2.5 Customer shall operate and maintain the QF in accordance with those practices and methods, as they are changed from time-to-time, that are commonly used in prudent engineering and electric utility operations and shall operate the QF lawfully and in a safe, dependable and efficient manner.

2.6 Customer shall submit to Company written equipment specifications and detailed plans to Company for the installation and operations of its QF, interconnection facilities, control and protective devices and facilities to accommodate Company's meter(s) for review and advance written approval prior to their actual installation. After Company's approval Customer shall not change or modify equipment specifications, plans, control and protective devices, metering and in general the QF's system configuration. If Customer desires to make such changes or modifications, Customer shall resubmit to Company plans describing said changes or modifications for approval by Company. No such change or modification may be made without the prior written approval of Company.

2.7 In the event it is necessary for Company to install interconnection facilities on its system (including, but not limited to control or protective devices, or any other facilities) in order to receive or continue to receive or to deliver electric power under the terms of the Purchase Agreement, Company shall inform Customer of the cost thereof in advance of incurring the costs of such facilities and Customer shall reimburse Company for the costs incurred by Company in connection with such facilities to the extent that said costs exceed those normally incurred by Company with respect to those customers which it serves who do not have self generation facilities.

2.8 If Customer utilizes the Company's system to facilitate start-up of its QF, the voltage flicker level shall not exceed Company standards.

3. METERING PROVISIONS

3.1 Customer shall provide and install at no expense to Company, and in accordance with Company's service standards, meter sockets and metering cabinets in a suitable location to be determined by Company's representatives.

3.2 Company shall furnish, own, install and maintain all meters that register the sales of power to, and the purchases of energy from Customer. The responsibility for the costs of providing and maintaining the required meters shall be as outlined in the applicable Rate for Purchase, or as specified in the Purchase Agreement.

3.3 The readings of all said meters will be conclusive as to the amount of electric power and energy supplied to the QF and/or purchased by Company unless, upon test, the meters are found to be in error by more than three percent (3%). The expense of any meter test requested by Customer will be borne by Customer unless such test shows the meter(s) to be in error by more than three percent (3%).

4. MUTUAL UNDERSTANDINGS

4.1 Company shall be allowed to install on Customer's premises any instrumentation equipment for research purposes. Such equipment shall be owned, furnished, installed and maintained by Company.

4.2 Company's approvals given pursuant to the Purchase Agreement shall not be construed as any warranty or representation to Customer or any third party regarding the safety, durability, reliability, performance or fitness of Customer's generation and service facilities, its control or protective devices or the design, construction, installation or operation thereof.

4.3 Company (including its employees, agents, and representatives) shall have the right to enter Customer's premises at all reasonable times to (a) inspect Customer's QF, protective devices and to read or test instrumentation equipment that Company may install, provided that as reasonably possible, notice is given to Customer prior to entering its premises; (b) maintain Company equipment relative to the purchase of electric energy from Customer; (c) read or test the meters; and (d) disconnect the QF without notice if, in Company's opinion, a hazardous condition exists and such immediate action is necessary to protect persons, or Company's facilities or other customers' or third parties' property and facilities from damage or interference caused by Customer's QF, or improperly operating protective devices.

4.4 All suitable easements or rights-of-way (required by Company in order to accommodate inter-connection of Company's system with the QF), which are either on premises owned, leased or otherwise controlled by Customer, or upon other property, shall be furnished in Company's name by Customer without cost to or condemnation by Company and in reasonable time to meet the requirements of the Purchase Agreement. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

4.5 Company is not obligated to pay for electric energy or capacity from Customer during any periods when such purchases would result in costs greater than those which Company would otherwise incur had Company generated said energy itself or purchased the energy from another source. Company will give reasonable notice to Customer when such periods exist, so that Customer can discontinue deliveries of energy to Company or elect to continue to sell to Company at a rate, lower than the standard purchase rate, estimated to be the avoided system cost for the period during which such situations exist.

4.6 Company will not install and maintain any lines or equipment on Customer's side of the Point Of Interconnection except its meter (and possibly some research equipment). For the mutual protection of Customer and Company, only authorized employees of Company are permitted to make and energize the interconnection between Company's system and that of Customer's QF. Such employees carry credentials which they will show to Customer upon request.

4.7 The particular rate for purchases applicable to a QF may be dependent on the system configuration of its facilities. Because of the varied and diverse requirements and operating characteristics associated with such facilities, it will be the QF's responsibility to evaluate and determine which system configuration and attendant purchase rate is most appropriate. Company will cooperate with Customer by providing suitable information to enable the Customer to assess the options available; provided, however, that no such information or assistance shall be deemed a representation or warranty by Company with respect to the contents of such information or any particular option available to Customer.

4.8 Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules or at Company's option.

4.9 The interconnection of Company's system with that of Customer will normally be arranged to accept only one type of standard service at one Point Of Interconnection. However, if Customer's QF requires a special type of service (e.g., supplemental, back-up, maintenance or interruptible power in addition to its normal service), or its sales to Company are at a different voltage level than that of its purchases from Company, such service(s) will be provided pursuant to the specific terms outlining such requirements in the Purchase Agreement, applicable rate schedules, and/or other supplemental or special terms and conditions governing such service.

4.10 Each premises owned or controlled by Customer which is served by Company under the Purchase Agreement shall be metered and billed separately. As used herein, the term "premises" shall be deemed to mean a single tract of land owned or controlled by Customer, or separate adjacent or contiguous tracts of land owned or controlled by Customer, operated by it as one tract under the same name or as part of the same business, and not separated by any private or public lands or rights-of-way owned or controlled by third parties.

4.11 All bills rendered for Company services provided to Customer under the provisions of the Purchase Agreement are due and payable upon presentation and are past due fifteen calendar days after mailing of bill. Company reserves the right to suspend or terminate Customer's service for non-payment of service bills past due, for non-payment of interconnection charges, and for non-payment of meter test charges. Past-due service bill amounts, past-due interconnection charges and past-due meter test charges, are subject to an additional charge at the rate of 1-1/2% per month during the period of delinquency.

5. SERVICE RENDERED UNDER SPECIAL AGREEMENT

Purchases will be made from Customer's QF in accordance with the Purchase Agreement, these terms and conditions and any changes required by law, regulation, rule, or order of applicable governmental authority, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of QF's, whose requirements are of unusual size or characteristics, additional or special rate and contract arrangements may be required.

6. REGULATORY AUTHORITY

The rates, terms and other contract provisions governing electric power sold to Customer and the rates or other contract provisions for purchases by Company from Customer are subject to the jurisdiction of the Corporation Commission (ACC) and nothing contained herein shall be construed as affecting or limiting in any way the right of Company (a) to make unilateral filings of changed rates, terms and other contract provisions, which shall be effective when filed, or within a specified number of days thereafter as specified therein, such rates or other contract provisions specified in such filing to be subject to modification if required by a final decision of the ACC, or (b) to unilaterally make application to the ACC for changes in such rates or other contract provisions, following a hearing and decision as permitted by law and the ACC's rules and regulations.

7. INDEMNITY AND INSURANCE

Each Party hereby agrees to indemnify the other Party, its officers, agents, and employees against all loss, damages, expenses and liability to third persons for injury to or death of person or injury to or loss of property, proximately caused by the indemnifying Party's construction, ownership, operation, or maintenance of, or by failure of, any of such Party's works or facilities used in connection with the Purchase Agreement. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall also pay all costs and expenses that may be incurred by the other Party in enforcing this indemnity.

8. UNCONTROLLABLE FORCES

No Party shall be considered to be in default in the performance of any of its obligations under the Purchase Agreement (other than obligations of said Party to pay sums to be paid by it hereunder, and other costs and expenses) when a failure of performance shall be due to an uncontrollable force. The term "uncontrollable force" shall be any cause beyond the control of the Party affected, including but not restricted to failure of or threat of failure of facilities, flood, earthquake, tornado, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, strikes, labor or material shortage, sabotage, restraint by court order or public authority, and action or non-action by or in- ability to obtain the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it shall be unable to overcome. Nothing contained herein shall be construed so as to require a Party to settle any strike or labor dispute in which it may be involved. Either Party rendered unable to fulfill any of its obligations under this Agreement by reason of an uncontrollable force shall give prompt written notice of such fact to the other Party and shall exercise due diligence to remove such inability with all reasonable dispatch.

9. NOTICES

Any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party to the other may be so given by certified or registered mail, addressed to the Party or personally delivered to the Party at the place designated in the applicable section of the Purchase Agreement. Changes in such designation may be made by notice similarly given.

10. CONFLICTS

10.1 In case of an inconsistency or conflict between any provision of the Purchase Agreement, a rate schedule and/or these terms and conditions, the inconsistency shall be resolved by giving priority to the Purchase Agreement, the rate and then the terms and conditions in said respective order.

11. SUCCESSORS AND ASSIGNS

Purchase Agreement shall be binding upon and for the benefit of the successors and assigns of Customer and Company, but no assignment by Customer shall be binding until accepted in writing by Company (which acceptance shall not be unreasonably withheld) and until the assignee in writing assumes the obligations of Customer under the Agreement.

# SCHEDULE 3
# CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

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

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

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

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

1. CONSTRUCTION ALLOWANCE - RESIDENTIAL ONLY

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

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

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

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

1.2 FREE EXTENSIONS - May be made if the conditions specified in Section 1.1 are met and such free extension does not exceed a total construction cost of $3,500.

1.3 EXTENSIONS OVER THE FREE ALLOWANCE

For extensions which meet the conditions specified in Section 1.1 above, and which exceed the free Construction Allowance specified in Section 1.2, Company may extend its facilities up to the maximum allowed in Section 1.1.2 provided the customer or customers will sign an extension agreement and make a non-refundable contribution for the difference between the maximum allowed in Section 1.2 and Company's estimated cost of the extension.

2. REVENUE BASIS - NON-RESIDENTIAL

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

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

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

2.2 FREE EXTENSIONS

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

2.3 EXTENSIONS OVER THE FREE LIMITS

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

3. ECONOMIC FEASIBILITY BASIS

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

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

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

3.2 FREE EXTENSIONS

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

3.3 EXTENSIONS OVER THE FREE LIMITS

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

4. OTHER CONDITIONS

4.1 IRRIGATION CUSTOMERS

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

4.2 TEMPORARY CUSTOMERS

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

4.3 DOUBTFUL PERMANENCY CUSTOMERS

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

4.4 REAL ESTATE DEVELOPMENT

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

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

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

5. REFUNDS

5.1 REVENUE AND ECONOMIC FEASIBILITY BASIS REFUNDS

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

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

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

5.2 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

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

5.3 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

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

5.4. GENERAL REFUND CONDITIONS

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

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

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

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

6. UNDERGROUND CONSTRUCTION

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

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

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

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

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

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

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

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

7. GENERAL CONDITIONS

7.1 VOLTAGE

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

7.2 THREE PHASE

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

7.3 EASEMENTS

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

7.4 GRADE MODIFICATIONS

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

7.5 OWNERSHIP

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

7.6 MEASUREMENT AND LOCATION

7.6.1 Measurement must be along the proposed route of construction.

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

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

7.7 UNUSUAL CIRCUMSTANCES

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

7.8 NON-STANDARD CONSTRUCTION

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

7.9 ABNORMAL LOADS

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

7.10 RELOCATIONS AND/OR CONVERSIONS

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

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

7.11 CHANGING OF MASTER METER TO INDIVIDUAL METER

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

7.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

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

7.13 DESIGN DEPOSIT

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

7.14 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

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

7.15 SETTLEMENT OF DISPUTES

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

7.16 INTEREST

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

7.16 EXTENSION AGREEMENTS

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

7.17 ADDITIONAL PRIMARY FEED

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

# SCHEDULE 4
# TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

Arizona Public Service Company (Company) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SESs) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single site.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 7 are all satisfied.

   1. The customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1) ; and

   2. Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and

   3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and

   4. For Standard Offer customers, totalized metering must be accomplished by a physical wire interconnection of metering information with the customer providing conduit between the SES'; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule 10, Terms and Conditions for Direct Access; and

   5. The customer shall provide vault or transformer space, which meets Company specifications, on the customer's property at no cost to Company; and

   6. If the customer operates an electric generation unit on the premise, totalized metering will be permitted when the customer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected customer owned generation; and

   7. Written approval by Company's authorized representative is required before totalized metering may be implemented.

B. Adjacent Totalized Metering will apply when conditions A.1-A.7 and the following conditions are met:

   1. The customer's <u>total</u> load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

   2. Company requires that load be split and served from multiple SESs; and

   3. The customer must locate SESs to be totalized within 10 feet of each other.

   There will be no additional charge to the customer's monthly bill for Adjacent Totalized Metering.

C. Remote Totalized Metering will apply when conditions A.1-A.7 are met, multiple SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

2. The customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

3. The customer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the customer receiving Remote Totalized Metering. However, lower capital investment which results from the customer's contribution, other than the meter costs in C.3 above, shall not be considered.

For customers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus $500.00, plus all applicable taxes and adjustments.

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.

2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.

3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

1. Company shall have no liability of obligation for claims arising out of the procedures for curtailment or interruption of electric service effected by it in accordance with such guidelines or such supplemental, amendatory or implementary guidelines or regulations as may hereafter be established and as provided by law.

2. Company shall endeavor to identify any electric customer(s) who might be classified as having either essential or critical loads. In the event that any customer of Company is dissatisfied by the classification of Customer by Company, or with the amount of such customer's load (if any) classifie4d by the Company as critical or essential, the Customer may bring the matter to either the Company or the Commission and request a determination in regard thereto. However, until such redetermination is made by the Commission or the Company, customer's original classification for purposes of electric curtailment under this Schedule shall be unaffected.

3. Company shall endeavor to, as circumstances permit and as further discussed in the Company's detailed Electric Load and Curtailment Plan, to notify County emergency personnel, or similar local authorities, of existing or developing situations involving the curtailment or interruption of APS customers pursuant to this Schedule #5.

4. DEFINITIONS

4.1 Essential Loads – Loads necessary to serve facilities used to protect the heath and safety of the public, such as: hospitals, 911 Centers, national defense installations, sewage facilities and domestic water facilities. Loads necessary to serve 911 Centers, police stations, and fire stations, which do not have independent back-up generation and require APS' electric service for operation of essential emergency equipment.

4.2 Critical Loads – That portion of the electric load of nonresidential customers, which in the event of 100 percent curtailment of service, would cause excessive damage to equipment or material being processed, or where such interruption would create grave hazards to employees or the public.

4.3 Major Use Customers/Others (With Notice) – Those customers having relatively large loads (over 1000 kW) or a substantial number of employees or other special circumstances that make it appropriate to schedule blackouts or curtailments different from typical customers. Customers who qualify as Major Use/Others (With Notice) can take 100 percent curtailment when sufficient notice is provided. These loads will be interrupted after the required notification period. "Sufficient", "required", and "appropriate" notice is that notice that APS, after consultation with the affected customer, has determined will allow the customer to curtail in a safe and efficient manner. Such notice necessarily varies from customer to customer.

4.4 Others (With or Without Notice) – All customers not meeting the above definitions. These customers will be interrupted (with or without notice) if voluntary curtailment measures are not sufficient to alleviate the situation.

5. GUIDELINES TO BE APPLICABLE IN EVENT OF INTERRUPTION OR CURTAILMENT OF ELECTRIC SERVICE BY COMPANY TO ITS CUSTOMERS DUE TO POWER SUPPLY INTERRUPTIONS, FUEL SHORTAGE OR TRANSMISSION EMERGENCY PURSUANT TO CORPORATION COMMISSION RULE R14-2-208, PROVISION OF SERVICE, PARAGRAPH E.

5.1 Operating Procedures Prior to Customer Load Curtailment

5.1.1 The following items shall be pursued concurrently.

5.1.1.1 Reschedule maintenance of transmission components and generating units, where practical.

5.1.1.2 Utilize spinning reserve.

5.1.1.3 Discontinue all non-firm wholesale sales during any period of involuntary curtailment or when an involuntary curtailment is anticipated.

5.1.1.4 Do not enter into any new wholesale sales during any period of involuntary curtailment or when an involuntary curtailment is anticipated.

5.1.1.5 Start all standby units.

5.1.1.6 Contact other utilities and/or agencies for emergency assistance.

5.1.1.7 Invoke emergency and short-term contractual schedules with other utilities and/or agencies.

5.1.1.8 Reduce system voltage, where practical.

5.1.1.9 Reduce non-essential Company uses such as flood lighting, sign lighting, display lighting, office lighting, electric cooling and heating, etc., where practical.

5.1.1.10 Provide information through the media or other appropriate medians to the public which will contain instructions on how customers can assist Company in case of an emergency power outage.

5.2 Voluntary Customer Load Curtailment

5.2.1 Public Appeal

5.2.1.1 An advisory message procedure will be used when Company has advance indications that it will not be able to meet future peak loads. These messages will request voluntary load reduction during specific hours on specific days.

5.2.1.2 An emergency bulletin procedure will be used for instant notification to the public in the event there is no advance indication of a power shortage. These bulletins will request the immediate voluntary cooperation of all customers in reducing electric loads.

5.2.1.2.1 These bulletins will request all customers to reduce the use of all electrically operated equipment and devices, where possible.

5.2.1.2.2 Company will have a prepared statement to read which will give current information on the Power Supply Interruption, Fuels Shortage or Transmission Emergency.

5.3 Contractually Interruptible Load

5.3.1 Company shall invoke contractual interruption provisions to the extent appropriate.

5.3.2 Company shall interrupt non-firm wholesale customer(s) as appropriate.

5.4 Involuntary Customer Load Curtailment

5.4.1 If the load reduction realized from application of the voluntary curtailment procedures is not sufficient to alleviate the power shortage, Company will reduce voltage if and to the extend practical and in accordance with normal applicable electric utility operation standards.

5.4.2 If further load reduction is required, load will be reduced as follows:

5.4.2.1 Circuits not classified with "Major Use/Others With Notice, Critical or Essential" customers will be interrupted on a rotating basis. The frequency and duration of such interruptions will be dependent upon the magnitude and nature of the power shortage. The frequency and duration of such interruptions shall also consider the circumstances of Major Use Customers.

5.4.2.2 Accurate records will be kept to ensure that these circuits are rotated in an equitable and technically feasible manner.

5.4.2.3 Circuits classified as "Major Use/Others" will be interrupted upon the giving of appropriate notice.

5.4.2.4 Customers on circuits which serve critical loads will be required to curtail the non-critical portion of their loads. Thereafter, circuits which serve critical loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as critical may be curtailed if they possess back-up generation sufficient to meet their entire load requirement. If a customer having a critical load refuses or fails to curtail his electric consumption down to the critical load, he shall thereupon not be considered to have a critical load for purposes of this Schedule.

5.4.2.5 Circuits which serve essential loads will be identified and will not interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as essential may be curtailed if they possess back-up generation sufficient to meet their entire load requirement.

5.5 Sudden Shortages of Power

In the event that time does not allow for the implementation of the Electric Curtailment Guidelines, Company may resort to its emergency operations procedures, with or without notice.

5.6 Automatic Load Shedding

In the event that there is a major electrical disturbance threatening the interconnected Southwest system with blackout conditions, emergency devices such as under frequency load shedding, transfer tripping, etc., will be utilized to maintain the optimum system stability.

6. ELECTRIC CURTAILMENT OF FIRM WHOLESALE CUSTOMERS

6.1 The term "firm wholesale customer" shall be defined as those APS customers who purchase, on a firm basis, electricity from the Company for purposes of resale.

6.2 In any given instance where a curtailment of wholesale power deliveries is involved, and subject to any required approvals of the Federal Energy Regulatory Commission or contractual provisions to the contrary, Company shall notify its firm wholesale customers, requesting that they curtail electric service to their retail customers during the period that Company's system is affected by power shortages. In the event that Company is unable to obtain the cooperation of a firm wholesale customer, it may seek an order from appropriate governmental authority requiring the firm wholesale customer to accept a reduction of electricity deliveries proportionate to the curtailment being effected on Company's system.

7. ELECTRIC LOAD AND CURTAILMENT PLAN

A detailed electric load and curtailment plan shall be kept on file with the Arizona Corporation Commission. This plan shall contain specific procedures for implementation of the above, along with the name(s) and telephone number(s) of the appropriate Company personnel to contact in the event implementation of the plan becomes necessary. This plan shall be updated at least annually, and it or amendments thereto shall become effective upon submission to the Arizona Corporation Commission.

7.1 Company shall contact the Director, Utilities Division, or their designee, as soon as practical for any curtailment pursuant to this Schedule #5.

# SCHEDULE 7
# ELECTRIC METER
# TESTING AND MAINTENANCE PLAN

General Plan

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

Specific Plan

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

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

   *Reference: ANSI C12.1-2001 sections 5.1.4 through 5.1.5.4 or as may be amended by ANSI*

   1.2 Analysis of the test results for each group evaluated shall be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 – 1993 Formulas B-3, Tables A-1, A-2 and B-5. The minimum sample size shall be 100 meters when possible.

2. Single Phase Self Contained Meters – Solid State

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

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

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

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

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

   3.3 Three phase lagged-demand meters: 8 years.

4. Three Phase Self-Contained Meters – Solid State

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

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

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

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

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

5.3 Installations over 2000 kW load: 1 year.

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

Customer Selections

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

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

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

1. General Terms

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

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

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

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

2. General Obligations of Company

2.1. Non-Discrimination

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

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

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

2.2. Transmission and Distribution Service

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

3. General Obligations of ESPs

3.1. Timeliness, Due Diligence and Security Requirements

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

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

3.2. Arrangements with ESP Customers

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

3.3. Responsibility for Electric Purchases

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

3.4. Company Not Liable for ESP Services

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

3.5. Load Aggregation for Procuring Electric Generation/Split Loads

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

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

3.6. Interval Metering

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

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

3.7. Meter Data Requirements

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

3.8. Statistical Load Profiles

Pursuant to R14-2-1604(B)(3) Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9 Fees and Other Charges

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

3.10. Liability In Connection With ESP Services

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

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

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

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

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

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

4. Customer Inquiries and Data Accessibility

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

4.1.1 Materials to consumers about competition and consumer choices.

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

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

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

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

4.3 Customer Inquires Concerning Billing Related Issues

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

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

4.4. Customer Inquiries Related to Emergency Situations and Outages

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

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

5. ESP Service Establishment

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

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

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

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

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

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

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

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

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

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

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

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

6. Direct Access Service Request (DASR)

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

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

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

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

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

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

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

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

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

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

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

6.8. DASRs that do not require a meter exchange must be received by Company at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date would be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

6.9 DASRs that require a meter exchange will have an effective change date to Direct Access as of the meter exchange date. Notification of meter exchange dates shall be coordinated between the ESP, MSP and Company's Meter Activity Coordinator ("MAC").

6.10. If more than one (1) RQ DASR is received for a service delivery point within a Customer's billing cycle, only the first valid DASR received shall be processed in that period. All subsequent DASRs shall be rejected.

6.11. Upon acceptance of an RQ DASR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP shall be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date.

6.12. Customers returning to Company Standard Offer service must contact their ESP. The ESP shall be responsible for submitting the DASR on behalf of the customer.

6.13. ESPs requesting to return a Direct Access customer to Company Standard Offer service shall submit a TS DASR and shall be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.

6.14. Customers requesting to return to Company Standard Offer service are subject to the same timing requirements as used to establish Direct Access Service.

6.15. Company may assess a fee for processing DASRs. All fees are payable to Company within fifteen (15) calendar days after the invoice date. All unpaid fees received after this date will be assessed applicable late fees pursuant to Schedule 1. If an ESP fails to pay these fees within thirty (30) days after the due date, Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the fees due is currently available or until such time as the fees are paid. If an ESP is late in paying fees, a deposit or an additional deposit may be required from the ESP.

6.16. A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact Company to establish a Service Account. The customer will be provided the necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in Section 6.8 and 6.9.

6.17. Billing and metering option changes are requested through a UC DASR and cannot be changed more than once per billing cycle.

6.18. Company shall not hold the ESP responsible for any customer unpaid billing charges prior to the customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs and shall remain the customer's responsibility to pay Company. Company's Schedule 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. Company shall not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by Company of a delinquent customer shall not make Company liable to the ESP or third-parties for the customer's disconnection.

6.19 Company shall not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

7.1 ESPs may select among the following billing options:

7.1.1 COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL COMPANY/ESP BILLING

7.2 COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to Company, and Company sends a consolidated bill containing both Company and ESP charges to the Customer.

7.2.2 Company Obligations:

7.2.2.1 Company shall bill the ESP charges and send the bill either by mail or electronic means to the customer. Company is not responsible for computing or determining the accuracy of the ESP charges. Company is not required to estimate ESP charges if the expected bill ready data is not received nor is Company required to delay Company billing. Billing rendered on behalf of the ESP by Company shall comply with A.A.C. R14-2-1612.

7.2.2.2 Company bills shall include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.

7.2.2.3 If Company processes Customer payments on behalf of the ESP, the ESP shall receive payment for its charges as specified in Section 7.7.

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer Company UDC Consolidated Billing services to Direct Access customers pursuant to the terms and conditions of the applicable ACC approved tariff.

7.2.3.2. The ESP shall submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to Company's meter reading schedule, and pursuant to the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1. Bills under this option will be rendered once a month. Nothing contained in this Schedule shall limit Company's ability to render bills more frequently consistent with Company's existing practices. However, if Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2. Except as provided in Section 7.2.4.1, Company shall require that all ESP and Company charges be based on the same billing period data.

7.2.4.3. ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this deadline, Company will render a bill for Company charges only. The ESP must wait until the next billing cycle, unless there is a mutual agreement for Company to send an interim bill. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that Company charges were previously billed.

7.2.4.4. ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, Company will render the customer's final bill for Company charges only, without the ESP's final charges. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5. Restrictions

Company UDC Consolidated Billing shall be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under Company UDC Consolidated Billing.

7.3. ESP CONSOLIDATED BILLING

7.3.1 Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP shall be obligated to provide the customer detailed Company charges to the extent that the ESP receives such detail from Company. The ESP is not responsible for the accuracy of Company charges.

7.3.2 Company Obligations:

7.3.2.1 Company shall calculate all its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. Company and the ESP may mutually agree to alternative options for the calculation of Company charges.

7.3.2.2 Company shall provide the ESP with sufficient detail of its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming.

7.3.2.3 For a Physical Disconnect Final Bill, Company will provide the ESP with Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges. The ESP shall include a message on the bill stating that Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

7.3.3 ESP Obligations:

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill shall include any billing-related details of Company charges. Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of Company by the ESP shall comply with A.A.C. R14-2-1612.

7.3.3.3 Other than including the billing data provided by Company on the customer's bill, the ESP has no obligations regarding the accuracy of Company charges or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.

7.3.3.4 The ESP shall process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all charges due to Company and not disputed by the customer as specified in Section 7.7.2.1.

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer customers customized billing cycles or payment plans which permit the Customer to pay the ESP for Company charges in different amounts than Company charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay all Company charges in full. Should Customer select an optional payment plan, all Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

ESPs may render bills more or less frequently than once a month. However, Company shall continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY/ESP BILLING

Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company and the ESP. Company and the ESP shall process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, Company shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If Company is providing Consolidated billing services, Company shall continue to provide these notices.

7.5.2 Under Company UDC Consolidated Billing, ESP bill inserts may be included pursuant to the applicable Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or Company if providing such services) shall resolve any meter errors and must notify the ESP and Company, as applicable, so any billing adjustments can be made. All other affected parties, including the appropriate Scheduling Coordinator, shall be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of Customer's energy or demand. If the MSP, MRSP, ESP or Company becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 Company UDC Consolidated Billing

7.6.1.3.1 Company shall be responsible for notifying Customer and adjusting the bill for its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP shall be responsible for any recalculation of the ESP charges. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to Customer's next normal monthly bill, unless there is mutual agreement to have Company send an interim bill to the Customer including the ESP's charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP shall be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer shall be solely responsible for obtaining refunds of ESP electric generation overcharges from its current and prior ESPs, as appropriate.

7.6.1.4.2 Company shall transmit its adjusted charges and any refunds to the ESP with Customer's next normal monthly bill. The ESP shall apply the charges to Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to Customer including Company charges.

7.6.1.5 Dual Company/ESP Billing

7.6.1.5.1 Company and the ESP shall be separately responsible for notifying Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 Company UDC Consolidated Billing

7.7.1.1 Company shall remit payments to the ESP for the total ESP charges collected from Customer within three (3) working days after Customer's payment is received. Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by Company.

7.7.1.2 Customer is obligated to pay Company for all undisputed Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing services agreement between ESP and Company.

7.7.1.4 Payment for any Company charges for Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date Company charges are rendered to the ESP. Any payment not received within this time frame will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 Payment is due in full from the ESP within fifteen (15) calendar days after the date Company's charges are rendered to the ESP. The ESP shall pay all undisputed Company charges regardless of whether Customer has paid the ESP. All payments received after fifteen (15) calendar days will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2.2 Company shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual Company/ESP Billing

Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 Company UDC Consolidated Billing

7.8.1.1 Company shall not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All Customer payments shall be applied first to unpaid balances identified as Company charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212, but a Customer will not otherwise have the right to direct partial payments between Company and the ESP.

7.8.1.3 ACC rules shall apply to late or non-payment of all Company customer charges. Undisputed Company delinquent balances owed on a customer account shall be considered late and subject to Company late payment procedures.

7.8.2 ESP Consolidated Billing

The ESP shall be responsible for collecting both unpaid ESP and Company charges, sending notices informing Customers of unpaid ESP and Company balances, and taking appropriate actions to recover the amounts owed. Company shall not assume any collection obligations under this billing option and ESP is liable to Company for all undisputed payments owed Company.

7.8.3 Dual Company/ESP Billing

Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with Company charges must be directed to Company.

7.9 Service Disconnects and Reconnects

In accordance with ACC rules, Company has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of Company's final bills or any past due charges by Customer, or evidence of safety violations, energy theft, or fraud, by Customer. The following provides for service disconnects and reconnects.

7.9.1 Company shall notify Customer and Customer's ESP of Company's intent to disconnect electric service for the non-payment of Company charges prior to disconnecting electric service to the Customer. Company shall further notify the ESP at the time Customer has been disconnected. To the extent authorized by the ACC, a service charge shall be imposed on Customer if a field call is performed to disconnect electric service.

7.9.2 Company shall reconnect electric service for a fee when the criteria for reconnection have been met to Company's satisfaction. Company shall notify the ESP of a Customer's reconnection.

7.9.3 Company shall not disconnect electric service to Customer for the non-payment of ESP charges by Customer. In the event of non-payment of ESP charges by Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to Company Standard Offer Service. Company will then advise the Customer that they will be placed on Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10. Involuntary Service Changes

7.10.1. A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

7.10.1.1. The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and Company exercises a contractual right to change billing options.

7.10.1.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.5. The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and Company tariffs and schedules.

7.10.2. Change of Service Election in Exigent Circumstances

In the event Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company elects to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, Company shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule. Company shall provide such notice and opportunity to remedy the problem if there are reasonable circumstances prevailing. Additionally, Company shall notify the ACC of the circumstances that required the change or the termination and the resulting action taken by Company. The ESP and/or Customer shall have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to Customer other than as provided in Section 4.4.2 .

7.10.3. Change in Service Election Absent Exigent Circumstances

7.10.3.1. In the event Company finds that an ESP has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company seeks to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3), and the failure does not constitute an emergency (as defined in Section 7.10.2) or involve an ESP's unauthorized energy use, Company shall notify the ESP and the ACC of such finding in writing stating the following:

7.10.3.1.1. The nature of the alleged failure;

7.10.3.1.2. The actions necessary to remedy the failure;

7.10.3.1.3. The name, address and telephone number of a contact person at the Company authorized to discuss resolution of the failure.

7.10.3.2. The ESP shall have thirty (30) calendar days from receipt of such notice to remedy the alleged failure or reach an agreement with Company regarding the alleged failure. If the failure is not remedied and no agreement is reached between Company and the ESP following this thirty (30) day period, Company may initiate the DASR process set forth in this Schedule to accomplish its remedy and shall notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the customer other than as provided in Section 4.4.2.

7.10.4. Termination of ESP Consolidated Billing

7.10.4.1. Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.1.1. The Company shall notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:

7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.

7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.

7.10.4.1.1.3 The ESP files for bankruptcy.

7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.

7.10.4.1.1.5 The ESP admits insolvency.

7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.

7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.

7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.

7.10.4.1.2. If the ESP fails to pay Company (or dispute payment pursuant to the procedures set forth in this Schedule) the full amount of all Company charges and fees by the applicable due date, Company shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by Company, Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.1.3. If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from Company of any additional credit, security or deposit requirements set forth in Sections 5.1.3 and 7.11, Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.2. Upon termination of ESP Consolidated Billing pursuant to Section 7.10.4, Company may deliver a separate bill for all Company charges which were not previously billed by the ESP.

7.10.4.3 Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections 5.1.4 and 7.11, and payment to Company of all costs associated with changing ESP customers' billing elections to and from dual billing.

7.10.4.4 In the event Company terminates ESP Consolidated Billing, Company will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.

7.10.5. Termination of Company UDC Consolidated Billing

7.10.5.1. Company may terminate Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to pay Company charges in connection with Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2.

7.10.5.2 Company may terminate Consolidated Billing upon providing thirty (30) days notice to an ESP if Company cancels or changes the tariff governing Company UDC Consolidated Billing.

7.10.6. Upon termination of ESP Direct Access services pursuant to Section 7.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by Customer, Company shall provide such services, until such time that Customer makes an election.

7.10.7. Company shall not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11. ESP Security Deposits

7.11.1. Company may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to pay Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through Schedule 10 and Company's other tariffs and schedules.

7.11.2. The amount of the security deposit required shall not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3. Security deposits required pursuant to Section 7.11 shall be in the form of a cash deposit accruing interest as specified in Section 2.7.4 of Company Schedule 1. Company shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4. Company may refuse to accept DASRs from, or provide other Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit pursuant to Section 7.11.

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, MSP and MSRP services.

8.2 Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for Residential Load-Profiled Customers

8.2.2 Services as authorized by the ACC.

8.2.3 Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for Company charges.

8.3 A Load Serving ESP may sub-contract Metering or Meter Reading Services to a certificated third party. If the ESP sub-contracts any of the components of these services to a third party, the ESP shall, for the purposes of this Schedule, remain responsible for the services.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

| | |
|---|---|
| ANSI C12.1 | Code for Electricity Metering |
| ANSI C12.6 | Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering |
| ANSI C12.7 | Watt-hour Meter Socket |
| ANSI C12.10 | Electromechanical Watt-hour Meters |
| ANSI C12.13 | Electronic TOU Registers for Electricity Meters |
| ANSI C12.18 | Type 2 Optical Port |
| ANSI C12.20 | 0.2% & 0.5% Accuracy Class Meters |
| ANSI C37.90 | Surge Withstand Test |
| ANSI 57.13 | Instrument Transformers (All CTs & PTs) |
| ANSI Z1.4 | Sampling Procedures and Tables for Inspection |
| ANSI Z1.9 | Sampling Procedures and Tables for Inspection |

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 NEC & Local Requirements by jurisdictions

8.5.6 Company's Electric Service Requirements Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Company's rate schedules.

8.6.2 If Company is providing MRSP functions for the ESP, pursuant to the Rules, meters must be compatible with Company's meter reading system.

8.6.3 No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet approved specifications, as set forth in Company's ESRM, or is in violation of any code listed in Section 8.5.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service shall be processed according to the following table prior to its re-installation:

| METER TYPE | REMOVAL REASON | ACTION REQUIRED |
|---|---|---|
| 1 Ph kWh Electro-Mechanical | Routine | Meter Inspection |
| 1 Ph kWh Electro-Mechanical | Trouble | Meter Test |
| 1 Ph kWh Hybrid or Solid State | Routine | Meter Test |
| 1 Ph TOU (all) | Trouble | Meter Test |
| | | |
| 3 Ph Meters (all) | All | Meter Test |
| | | |
| 1 Ph or 3 Ph IDR Meters | All | Meter Test |

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.4 Records on meter testing shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest meter test record shall be kept as long as the meter is in service.

8.8 Meter Test Requests

Pursuant to A.A.C. R14-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP shall take reasonable measures to detect meter error. The MSP shall notify Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error. ESPs and Company shall use a form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.

8.9 Meter Identification

8.9.1 The ESP or its agent shall install a Company provided unique number on each meter. Company will provide the unique numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter shall remain solely with that meter while in use in Company's service territory.

8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a blue seal that is imprinted with the name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

8.10.1 All metering equipment shall be installed according to all applicable ACC requirements and Company's Electric Service Requirements Manual.

8.10.2 An ESP or its agent must be authorized by Company to remove a Company owned meter. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days prior to the exchange. Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.

8.10.3 The ESP or its agent shall inform Company of all meter activity, such as meter installations or exchanges, via the Meter Activity Coordination (MAC) Form within the time frames specified above. If final meter reads are not provided to Company, are inaccurate, or otherwise result in Company not being able to render accurate final bills to customers pursuant to ACC Rules and Regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

8.10.4 The ESP or its agent shall return the existing meter to Company at one of Company's designated locations identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent shall be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 Company may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

8.11.2 For new construction, the party installing the meter shall ensure that the owner/builder has met the construction standards outlined in Company's ESRM, and Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements. Company shall perform a preinstallation inspection on all new construction. Local city/county clearances may also be required prior to energizing any new construction.

8.11.3 Company may require a site meet for: the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which Company forbids key access; cogeneration sites, bi-directional or detented metering sites; or upon request of an ESP or MSP. The ESP and Company's MAC shall coordinate the time of the site meet. If the ESP or MSP miss two (2) site meets, Company may cancel the applicable DASR. Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership shall be limited to Company, an ESP, or the customer. The customer must obtain the meter through Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 Company shall own the CTs, PTs and associated equipment.

8.12.3 All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in Company's ESRM. During meter exchanges, the ESP or its agent's employees who are certificated to perform the related MSP activities may install, replace or operate Company test switches and operate Company-sealed customer-owned test blocks.

8.13 Installation Options

8.13.1 The ESP is responsible for Direct Access customer meter installation. Company may optionally provide meter installation pursuant to the Rules.

8.13.2 ESPs or their agents must be certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP and their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certificated MSP.

8.13.2.2 Subcontracting with a third party that is a certificated MSP.

8.13.2.3 Subcontracting with Company under the circumstances described in Section 8.2.

8.14 As part of providing metering services, ESPs or their agents shall:

8.14.1 Obtain lock ring keys for meters originally installed by Company or request site meets with Company. Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the Company MAC.

8.14.2 If lock rings are used they shall meet Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from Company.

8.14.3 Provide information to Company on the specifications and other specifics on meters not purchased from or installed by Company.

8.14.4 Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows Company to remove meters, ESP shall coordinate with Company regarding the return of the meters.

8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.

8.14.6 Ensure that ESP and MSP employees working in Company's territory follow ACC and other applicable safety standards.

8.14.7 Company shall notify the ESP immediately and the ESP shall notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP shall ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and shall notify the ACC of any such action taken.

8.14.8 Take no action to impede Company's safe and unrestricted access to a customer's service entrance.

8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

8.15 MSRP Services provided as a responsibility of an ESP

Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations shall perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least ten (10) days prior to the next schedules read date. MSRP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1 Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file shall be posted immediately.

8.15.2 Both Company and the ESP shall have 24-hour/7 days per week access to the MRSP server.

8.15.3 Meter read data shall include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data shall be provided for all interval metering customers. Data must be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated data shall contain applicable reason codes pursuant to the 867 guidelines.

8.15.4 The MRSP shall provide Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.6 MRSPs shall read Customer's meter based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter shall contain the full period from read date to the following read date. Interval data cycles shall be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp shall begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 shall constitute the billing cycle. For meter exchanges back to Standard Offer, every interval shall be included up to the last full interval prior to the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.

8.15.7 The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by Company or Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for all meters.

8.16.1.1 Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

8.16.1.2 Meter read date and time shall be accurate.

8.16.1.3 All meter reading data shall be validated with the pursuant to the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

Pursuant to guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data shall be available by 3:00 p.m. Local Arizona Time (MST) on the third working day after the scheduled read date. If the meter data is not posted, is unavailable, or clearly contains errors by this deadline, the billing determinants including usage (kWh) and demand (kW) may be estimated by Company and the ESP shall be charged an approved charge for this service.

8.16.3 Proof of Operational Ability

Prior to performing MRSP services in Company's distribution service territory, or prior to making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in Company's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a Customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server shall be stored in Company-compatible EDI format.

8.17 Company performing MSP and MRSP functions:

If Company is eligible to perform Direct Access related MSP and MRSP functions as defined in section 8.2, the following restriction applies:

The validated meter read will be posted in EDI format no later than 6 working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the affected Customer. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party may be charged an ACC-approved tariff for the meeting.

8.18.2.2 Company may repair the defect, and the other party shall be responsible for all related expenses.

8.18.2.3 Company shall adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

8.18.3 Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to section 7.10.1.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

# SCHEDULE 15
# CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

Arizona Public Service Company (Company) will provide specialized metering upon customer request, provided the customer agrees to the following conditions:

1. The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR and KYZ pulse meters. The customer must specify whether a modem will be required.

2. If the customer requests a meter with a modem option, the customer will be required to install communication equipment and connections which shall include a RJ11 or RJ12 jack. A coil of communication cable with either an RJ11 or RJ12 jack is to be provided within five to ten feet of the meter panel location and in such a manner that will provide for ease of attachment of the jack to the meter panel by Company. The phone line must be installed prior to the installation of the meter. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).

3. If a customer requests kWh pulses, Company shall furnish an isolation relay and maintain the output wire and connections from this relay to an approved terminal block to be furnished by the customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) the Company metering compartment and not on the face of the Company metering panel.

4. The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

   4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.

   4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.

   4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

   Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

   Company will retain ownership of all meters and Company installed metering equipment.

   If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.

Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the customer stop the operation or in any way affect or interfere with the operation of the isolation relay and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.

6. Company reserves the right to interrupt the specialized metering circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the customer's demand control or other equipment. However, Company will make a good faith effort to notify the customer prior to any interruption of the specialized metering circuit.

7. The possible failure or malfunction of an isolation relay and subsequent loss of kWh contact closures to the customer's control equipment shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the kWh and demand record for billing purposes.

8. The accuracy of the customer's equipment is entirely the responsibility of the customer. Should the customer's equipment malfunction, Company will reasonably cooperate with the customer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the customer, unless the actual source of the malfunction is found within Company's equipment.

9. If Company provides pulse values in kWh, customer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.

10. No circuit for use by the customer shall be installed from Company's billing metering potential or current transformer secondaries.

11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the customer.

12. Upon request by Company, the customer shall make available to Company monthly load analysis information.

13. References to electric kWh pulses above shall mean isolation relay contact closures only; the customer is required to furnish operating voltage service. Isolation relay contacts are rated 5 amps, 28 volts DC or 120 volts AC.

14. The customer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of specialized metering.

15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.

16. Prior written approval by an authorized Company representative is required before electric kWh pulses service may be implemented.

# Application

## E-01345A-03-0437

## PART 1 OF 3
## BAR CODE # 0000000701

**To review remaining parts please see the following:**

**PART 2 OF 3 BAR CODED #0000108961**

**PART 3 OF 3 BAR CODED #0000108962**