PINNACLE WEST CAPITAL CORP

FORM 10-Q
(Quarterly Report)

Filed 11/14/03 for the Period Ending 09/30/03

Address	400 NORTH FIFTH STREET MS8695 PHOENIX, AZ 85004
Telephone	602 250 1000
CIK	0000764622
Symbol	PNW
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

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FORM 10-Q

Securities and Exchange Commission
Washington, D.C. 20549

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2003

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 1-8962

PINNACLE WEST CAPITAL CORPORATION

(Exact name of registrant as specified in its charter)

Arizona	86-0512431
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
400 North Fifth Street, P.O. Box 53999, Phoenix, Arizona	85072-3999
(Address of principal executive offices)	(Zip Code)
Registrant's telephone number, including area code:	(602) 250-1000

(Former name, former address and former fiscal year, if changed since last report)

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 ☒ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes ☒ No ☐

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Number of shares of common stock, no par value,
outstanding as of November 12, 2003: 91,275,079

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Glossary

ACC – Arizona Corporation Commission

ACC Staff – Staff of the Arizona Corporation Commission

AFUDC – allowance for funds used during construction

ALJ – administrative law judge

APS – Arizona Public Service Company, a subsidiary of the Company

APS Energy Services – APS Energy Services Company, Inc., a subsidiary of the Company

CAISO – California Independent System Operator

CC&N – Certificate of Convenience and Necessity

Citizens – Citizens Communications Company

Company – Pinnacle West Capital Corporation

CPUC – California Public Utility Commission

EITF – the FASB's Emerging Issues Task Force

El Dorado – El Dorado Investment Company, a subsidiary of the Company

ERMC –Energy Risk Management Committee

FASB – Financial Accounting Standards Board

FERC – United States Federal Energy Regulatory Commission

FIN – FASB Interpretation

Financing Order – ACC order issued on April 4, 2003 relating to APS' request to provide up to $500 million of financing or credit support to Pinnacle West Energy or the Company

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

Interim Financing Order – ACC order issued on November 22, 2002 relating to APS' request to provide up to $125 million of financing or credit support to the Company

IRS – United States Internal Revenue Service

June 2003 10-Q – Pinnacle West Capital Corporation Quarterly Report on Form 10-Q for the fiscal quarter

ended June 30, 2003

March 2003 10-Q – Pinnacle West Capital Corporation Quarterly Report on Form 10-Q for the fiscal quarter

ended March 31, 2003

Moody's – Moody's Investors Service

MW – megawatt, one million watts

MWh – megawatt-hours, one million watts per hour

NAC – NAC International Inc., a subsidiary of El Dorado

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

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

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NRC – United States Nuclear Regulatory Commission

OCI – other comprehensive income

Palo Verde – Palo Verde Nuclear Generating Station

PG&E – PG&E Corp.

Pinnacle West – Pinnacle West Capital Corporation, the Company

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

PWEC Dedicated Assets – the following Pinnacle West Energy power plants, each of which is dedicated to serving APS' customers: Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3

PX – California Power Exchange

Rules – ACC retail electric competition rules

SCE – Southern California Edison Company

SEC – United States Securities and Exchange Commission

SFAS – Statement of Financial Accounting Standards

SNWA – Southern Nevada Water Authority

SPE – special-purpose entity

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

SunCor – SunCor Development Company, a subsidiary of the Company

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

2002 10-K – the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2002

UniSource – UniSource Energy Corporation

VIE – variable interest entity

PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)
(in thousands, except per share amounts)

	Three Months Ended September 30,	
	2003	2002
Operating Revenues		
Regulated electricity segment	$694,306	$719,361
Marketing and trading segment	154,519	87,258
Real estate segment	75,009	43,547
Other revenues	22,736	21,224
Total	946,570	871,390
Operating Expenses		
Regulated electricity segment purchased power and fuel	235,663	257,484
Marketing and trading segment purchased power and fuel	156,156	43,361
Operations and maintenance	133,852	144,438
Real estate segment operations	63,196	44,041
Depreciation and amortization	110,997	108,672
Taxes other than income taxes	28,206	26,757
Other expenses	19,650	34,146
Total	747,720	658,899
Operating Income	198,850	212,491
Other		
Allowance for equity funds used during construction (Note 20)	11,194	—
Other income (Note 16)	5,533	3,026
Other expense (Note 16)	(5,791)	(10,713)
Total	10,936	(7,687)
Interest Expense		
Interest charges	52,571	49,255
Capitalized interest (Note 20)	(2,851)	(11,015)
Total	49,720	38,240
Income From Continuing Operations Before Income Taxes	160,066	166,564
Income Taxes	50,528	65,851
Income From Continuing Operations	109,538	100,713
Income From Discontinued Operations - Net of Income Tax Expense of $332 and $133	510	203
Net Income	$110,048	$100,916
Weighted-Average Common Shares Outstanding — Basic	91,271	84,768
Weighted-Average Common Shares Outstanding — Diluted	91,467	84,797
Earnings Per Weighted-Average Common Share Outstanding (Note 18)		
Income From Continuing Operations — Basic	$ 1.20	$ 1.19
Net Income — Basic	1.21	1.19
Income From Continuing Operations — Diluted	1.20	1.19
Net Income — Diluted	1.20	1.19
Dividends Declared Per Share	$ 0.425	$ 0.40

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)
(in thousands, except per share amounts)

	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Operating Revenues		
Regulated electricity segment	$1,585,898	$1,596,440
Marketing and trading segment	484,737	212,576
Real estate segment	172,886	127,352
Other revenues	64,494	28,382
Total	2,308,015	1,964,750
Operating Expenses		
Regulated electricity segment purchased power and fuel	434,442	423,606
Marketing and trading segment purchased power and fuel	447,499	109,625
Operations and maintenance	408,488	390,864
Real estate segment operations	157,297	123,219
Depreciation and amortization	323,471	310,114
Taxes other than income taxes	84,851	81,147
Other expenses	51,380	39,116
Total	1,907,428	1,477,691
Operating Income	400,587	487,059
Other		
Allowance for equity funds used during construction (Note 20)	11,194	—
Other income (Note 16)	13,886	10,139
Other expense (Note 16)	(15,079)	(26,787)
Total	10,001	(16,648)
Interest Expense		
Interest charges	151,539	140,538
Capitalized interest (Note 20)	(24,061)	(38,782)
Total	127,478	101,756
Income From Continuing Operations Before Income Taxes	283,110	368,655
Income Taxes	98,530	145,888
Income From Continuing Operations	184,580	222,767
Income From Discontinued Operations - Net of Income Tax Expense of $4,524 and $4,768	6,908	7,271
Net Income	$ 191,488	$ 230,038
Weighted-Average Common Shares Outstanding — Basic	91,262	84,768
Weighted-Average Common Shares Outstanding — Diluted	91,432	84,859
Earnings Per Weighted-Average Common Share Outstanding (Note 18)		
Income From Continuing Operations — Basic	$ 2.02	$ 2.63
Net Income — Basic	2.10	2.71
Income From Continuing Operations — Diluted	2.02	2.63
Net Income — Diluted	2.09	2.71
Dividends Declared Per Share	$ 1.28	$ 1.20

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)
(in thousands, except per share amounts)

	Twelve Months Ended September 30,	
	2003	2002
Operating Revenues		
Regulated electricity segment	$2,002,481	$2,033,006
Marketing and trading segment	598,092	229,996
Real estate segment	246,615	188,447
Other revenues	98,049	34,275
Total	2,945,237	2,485,724
Operating Expenses		
Regulated electricity segment purchased power and fuel	510,379	520,231
Marketing and trading segment purchased power and fuel	531,913	122,979
Operations and maintenance	602,162	512,654
Real estate segment operations	220,003	175,433
Depreciation and amortization	437,439	419,175
Taxes other than income taxes	111,656	102,114
Other expenses	117,223	45,464
Total	2,530,775	1,898,050
Operating Income	414,462	587,674
Other		
Allowance for equity funds used during construction (Note 20)	11,194	—
Other income (Note 16)	16,591	17,729
Other expense (Note 16)	(19,881)	(40,256)
Total	7,904	(22,527)
Interest Expense		
Interest charges	198,513	187,257
Capitalized interest (Note 20)	(29,028)	(51,240)
Total	169,485	136,017
Income From Continuing Operations Before Income Taxes	252,881	429,130
Income Taxes	84,870	170,557
Income From Continuing Operations	168,011	258,573
Income From Discontinued Operations - Net of Income Tax Expense of $5,628 and $4,768	8,592	7,271
Cumulative Effect of a Change in Accounting for Trading Activities - Net of Income Tax Benefit of $43,123	(65,745)	—
Net Income	$ 110,858	$ 265,844
Weighted-Average Common Shares Outstanding — Basic	89,760	84,746
Weighted-Average Common Shares Outstanding — Diluted	89,919	84,851
Earnings Per Weighted-Average Common Share Outstanding (Note 18)		
Income From Continuing Operations — Basic	$ 1.87	$ 3.05
Net Income — Basic	1.24	3.14
Income From Continuing Operations — Diluted	1.87	3.05
Net Income — Diluted	1.23	3.13
Dividends Declared Per Share	$ 1.70	$ 1.60

See Notes to Condensed Consolidated Financial Statements.

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PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(dollars in thousands)
ASSETS

	September 30, 2003	December 31, 2002
Current Assets		
Cash and cash equivalents	$ 201,746	$ 77,566
Customer and other receivables—net	421,428	374,569
Accrued utility revenues	106,861	72,915
Materials and supplies (at average cost)	93,443	91,652
Fossil fuel (at average cost)	29,524	28,185
Deferred income taxes	4,094	4,094
Assets from risk management and trading activities (Note 10)	84,276	102,664
Real estate assets held for sale (Note 19)	—	42,339
Other current assets	98,963	103,978
Total current assets	1,040,335	897,962
Investments and Other Assets		
Real estate investments—net	378,015	385,482
Assets from risk management and trading activities — long-term (Note 10)	156,950	191,754
Decommissioning trust accounts (Note 13)	226,709	194,440
Other assets	34,101	35,451
Total investments and other assets	795,775	807,127
Property, Plant and Equipment		
Plant in service and held for future use	9,718,815	9,058,900
Less accumulated depreciation and amortization	3,464,840	3,474,325
Total	6,253,975	5,584,575
Construction work in progress	581,030	777,542
Intangible assets, net of accumulated amortization (Note 14)	121,323	109,815
Nuclear fuel, net of accumulated amortization	15,139	7,466
Net property, plant and equipment	6,971,467	6,479,398
Deferred Debits		
Regulatory assets	186,479	241,045
Other deferred debits	118,810	113,194
Total deferred debits	305,289	354,239
Total Assets	$9,112,866	$8,538,726

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(dollars in thousands)
LIABILITIES AND EQUITY

	September 30, 2003	December 31, 2002
Current Liabilities		
Accounts payable	$ 322,417	$ 354,218
Accrued taxes	229,696	71,107
Accrued interest	50,673	53,018
Short-term borrowings	90,011	102,183
Current maturities of long-term debt	448,980	280,888
Customer deposits	50,338	42,190
Real estate liabilities held for sale	—	28,855
Liabilities from risk management and trading activities (Note 10)	86,095	111,329
Other current liabilities	56,972	64,443
Total current liabilities	1,335,182	1,108,231
Long-Term Debt Less Current Maturities	2,840,900	2,869,241
Deferred Credits and Other		
Liabilities from risk management and trading activities — long-term (Note 10)	94,448	147,900
Deferred income taxes	1,196,926	1,209,074
Regulatory liabilities	90,078	26,264
Unamortized gain — sale of utility plant	56,053	59,484
Pension liability	186,496	183,880
Liability for asset retirement (Note 13)	230,865	—
Other	278,542	248,499
Total deferred credits and other	2,133,408	1,875,101
Commitments and Contingencies (Note 12)		
Common Stock Equity		
Common stock, no par value	1,743,027	1,737,258
Treasury stock	(3,753)	(4,358)
Total common stock	1,739,274	1,732,900
Accumulated other comprehensive income (loss):		
Minimum pension liability adjustment	(71,264)	(71,264)
Derivative instruments	15,688	(20,020)
Total accumulated other comprehensive loss	(55,576)	(91,284)
Retained earnings	1,119,678	1,044,537
Total common stock equity	2,803,376	2,686,153
Total Liabilities and Equity	$9,112,866	$8,538,726

See Notes to Condensed Consolidated Financial Statements.

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PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)
(dollars in thousands)

	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
CASH FLOWS FROM OPERATING ACTIVITIES		
Income from continuing operations	$ 184,580	$ 222,767
Items not requiring cash:		
Depreciation and amortization	323,471	310,114
Nuclear fuel amortization	22,781	23,639
Allowance for equity funds used during construction	(11,194)	—
Deferred income taxes	(41,323)	136,584
Change in mark-to-market	9,522	(22,163)
Changes in current assets and liabilities:		
Customer and other receivables	(46,859)	(64,772)
Accrued utility revenues	(33,946)	(27,642)
Materials, supplies and fossil fuel	(3,130)	(3,262)
Other current assets	5,015	(12,590)
Accounts payable	(24,921)	(13,063)
Accrued taxes	158,589	7,446
Accrued interest	(2,345)	(3,690)
Other current liabilities	2,364	63,264
Change in real estate investments	6,951	(14,938)
Increase in regulatory assets	(10,681)	(8,709)
Change in risk management and trading — assets	35,747	(7,032)
Change in risk management and trading — liabilities	(11,489)	(29,353)
Change in customer advances	4,081	17,132
Change in pension liability	2,616	1,777
Change in other long-term assets	4,149	(21,513)
Change in other long-term liabilities	31,036	(24,246)
Net cash flow provided by operating activities	605,014	529,750
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(495,825)	(689,580)
Proceeds from sale of assets from discontinued operations	24,098	23,308
Capitalized interest	(24,061)	(38,782)
Other	(3,018)	41,724
Net cash flow used for investing activities	(498,806)	(663,330)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	542,154	613,757
Repayment of long-term debt	(404,284)	(286,676)
Short-term borrowings and payments—net	(9,926)	(95,416)
Dividends paid on common stock	(116,346)	(101,727)
Other	6,374	2,987
Net cash flow provided by financing activities	17,972	132,925
Net Cash Flow	124,180	(655)
Cash and Cash Equivalents at Beginning of Period	77,566	28,619
Cash and Cash Equivalents at End of Period	$ 201,746	$ 27,964
Supplemental disclosure of cash flow information:		
Cash paid during the period for:		
Interest paid, net of amounts capitalized	$ 120,098	$ 100,573
Income taxes paid	$ 9,674	$ 47,450

See Notes to Condensed Consolidated Financial Statements.

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PINNACLE WEST CAPITAL CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. The condensed consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, Pinnacle West Energy, APS Energy Services, SunCor and El Dorado (principally NAC). All significant intercompany accounts and transactions between the consolidated companies have been eliminated. We have reclassified certain prior year amounts to conform to the current year presentation (see Notes 10 and 19).

2. Our unaudited condensed consolidated financial statements reflect all adjustments which we believe are necessary for the fair presentation of our financial position and results of operations for the periods presented. These adjustments are of a normal recurring nature with the exception of the cumulative effect of a change in accounting for trading activities (see Note 10), the transition adjustment for asset retirement obligations (see Note 13) and real estate discontinued operations (see Note 19). We suggest that these condensed consolidated financial statements and notes to condensed consolidated financial statements be read along with the consolidated financial statements and notes to consolidated financial statements included in our Form 8-K filed on November 5, 2003 for reclassification of our 2002 financial statements due to discontinued real estate operations.

3. Weather conditions cause significant seasonal fluctuations in our revenues. In addition, trading and wholesale marketing activities can have significant impacts on our results for interim periods. Consequently, results for interim periods do not necessarily represent results to be expected for the year.

4. Our debt structure as of September 30, 2003 differed from our debt structure as of December 31, 2002 in the ways discussed in this Note. On April 7, 2003, APS redeemed approximately $33 million of its First Mortgage Bonds, 8% Series due 2025, and on August 1, 2003, APS redeemed approximately $54 million of its First Mortgage Bonds, 7.25% Series due 2023.

On May 12, 2003, APS issued $500 million of debt as follows: $300 million aggregate principal amount of its 4.650% Notes due 2015 and $200 million aggregate principal amount of its 5.625% Notes due 2033. Also on May 12, 2003, APS made a $500 million loan to Pinnacle West Energy, and Pinnacle West Energy distributed the net proceeds of that loan to us to fund our repayment of a portion of the debt incurred to finance the construction of the PWEC Dedicated Assets. See “ACC Financing Orders” in Note 5 for additional information. With Pinnacle West Energy’s distribution to us, on May 12, 2003, we repaid the outstanding balance ($167 million) under a credit facility. We used a portion of the remaining proceeds to redeem our $250 million Floating Rate Notes due 2003 on June 2, 2003 and to repay other short-term debt.

On November 12, 2003, we issued $165 million of our Floating Rate Senior Notes due 2005. The bonds are callable at par beginning November 1, 2004. The primary use of this financing is to ultimately repay at maturity our $215 million 4.5% Notes due February 2004.

5. Regulatory Matters

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 the 1999 Settlement Agreement, a comprehensive settlement agreement among APS and various parties related to the implementation of retail electric competition in Arizona. On September 10, 2002, the ACC issued the Track A Order, which, among other things, directed APS not to transfer its generation assets to Pinnacle West Energy, as previously required under the Rules and the 1999 Settlement Agreement. See "Track A Order" below. The Track A Order and legal challenges to the Rules have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona.

On March 14, 2003, the ACC issued the Track B Order, which required APS to solicit bids for certain estimated amounts of capacity and energy for periods beginning July 1, 2003. Pinnacle West Energy bid on and entered into a contract to supply most of APS' requirements in the summer months through September 2006. See "Track B Order" below.

On April 4, 2003, the ACC issued the Financing Order authorizing APS to lend up to $500 million to Pinnacle West Energy. See "ACC Financing Orders" below. On May 12, 2003, APS issued $500 million of debt pursuant to the Financing Order and made a $500 million loan to Pinnacle West Energy. Pinnacle West Energy distributed the net proceeds of that loan to us to fund the repayment of a portion of the debt we incurred to finance the construction of the PWEC Dedicated Assets. See Note 4.

On June 27, 2003, APS filed a general rate case with the ACC and requested a $175.1 million, or 9.8%, increase in its annual retail electricity revenues, to become effective July 1, 2004. The major components of the request are described under "APS General Rate Case and Retail Rate Adjustment Mechanisms" below.

1999 Settlement Agreement

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

- APS has reduced 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; approximately $28 million ($17 million after taxes), effective July 1, 2002; and approximately $29 million ($18 million after taxes), effective 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 APS 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 is 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 APS is 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 APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders.

- APS 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. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" below.

- APS' 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. APS opened its 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 and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that APS has demonstrated that its allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value (in 1999 dollars). The 1999 Settlement Agreement also states that APS will not be allowed to recover $183 million net present value (in 1999 dollars) of the $533 million. The 1999 Settlement Agreement provides that APS 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 of the $350 million due to sales volume variances. As discussed below under "APS General Rate Case and Retail Rate Adjustment Mechanisms," APS is seeking to recover amounts written off by APS as a result of the 1999 Settlement Agreement.

- The 1999 Settlement Agreement required APS to form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) its competitive electric assets and services no later than December 31, 2002. The 1999 Settlement Agreement provided that APS would be allowed to defer and later collect, beginning July 1, 2004, 67% of its 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 the Track A Order, an order preventing APS from transferring its generation assets. APS is seeking to recover all costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" below.

Retail Electric Competition Rules

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

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

- Effective January 1, 2001, retail access became available to all APS 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, APS received a waiver to allow transfer of its 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 APS to transfer its 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, APS 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 APS' 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. The Arizona Supreme Court agreed that the ACC had to determine a fair value rate base but vacated the Court of Appeals' requirement that competitive rates be set based only on such fair value rate base.

Provider of Last Resort Obligation

Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is 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 APS 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 APS' 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 APS' current retail rates. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain an adjustment of its rates under the emergency provisions of the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" below for a discussion of retail rate adjustment mechanisms that were the subject of ACC hearings in April 2003.

Track A Order

On September 10, 2002, the ACC issued the Track A Order, in which the ACC, among other things:

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

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

On November 15, 2002, APS 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 vs. Arizona Corporation Commission* , CV 2002-0222 32. *Arizona Public Service Company vs. Arizona Corporation Commission* , 1CA CC 02-0002. On December 13, 2002, APS and the ACC Staff agreed to principles for resolving certain issues raised by APS in its appeals of the Track A Order. APS and the ACC are the only parties to the Track A Order appeals. The major provisions of the principles include, among other things, the following:

- APS and the ACC Staff agreed that it would be appropriate for the ACC to consider the following matters in APS' general rate case, which was filed on June 27, 2003:

  - the generating assets to be included in APS' rate base, including the question of whether the PWEC Dedicated Assets should be included in APS' rate base;

  - the appropriate treatment of the $234 million pretax asset write-off agreed to by APS as part of the 1999 Settlement Agreement; and

  - the appropriate treatment of costs incurred by APS 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 APS' request to provide $500 million of financing or credit support to Pinnacle West Energy or the Company, with appropriate conditions, APS' 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. As noted below, the ACC issued the Financing Order on April 4, 2003. The Financing Order is final and no longer subject to appeal. As a result, APS' appeals of the Track A Order will be limited to the issues described in the preceding bullet points.

On February 21, 2003, a Notice of Claim was filed with the ACC and the Arizona Attorney General on behalf of APS, Pinnacle West and Pinnacle West Energy to preserve their and our rights relating to the Track A Order. The period within which the ACC and the Arizona Attorney General could respond to the claim expired on April 22, 2003. Accordingly, APS, Pinnacle West and Pinnacle West Energy filed a lawsuit in August 2003 asserting damage claims relating to the Track A Order. *Arizona Public Service Company et al. v. The State of Arizona ex rel.* , Superior Court of the State of Arizona, County of Maricopa, No. CV2003-016372.

Track B Order

On March 14, 2003, the ACC issued the Track B Order, which required APS to solicit bids for certain estimated amounts of capacity and energy for periods beginning July 1, 2003. For 2003, APS was required to solicit competitive bids for about 2,500 MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of APS' total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in APS' retail load and APS' 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 APS' right to reject any bids that are unreasonable, uneconomical or unreliable. The ACC Staff and an independent monitor participated in the Track B procurement process. The Track B Order also contains requirements relating to standards of conduct between APS and any affiliate of APS participating in the competitive solicitation, requires that APS treat bidders in a non-discriminatory manner and requires APS to file a protocol regarding short-term and emergency procurements. The order permits the provision by APS 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 confidential APS bidding information that is not available to other bidders. The order directs APS 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, the decision requires APS to prepare a report evaluating environmental issues relating to the procurement, and a series of workshops on environmental risk management will be commenced thereafter.

APS issued requests for proposals in March 2003 and, by May 6, 2003, APS entered into contracts to meet all or a portion of its requirements for the years 2003 through 2006 as follows:

(1) Pinnacle West Energy agreed to provide 1,700 MW in July through September of 2003 and in June through September of 2004, 2005 and 2006, by means of a unit contingent contract.

(2) PPL EnergyPlus, LLC agreed to provide 112 MW in July through September of 2003 and 150 MW in June through September of 2004 and 2005, by means of a unit contingent contract.

(3) Panda Gila River LP agreed to provide 450 MW in October of 2003 and 2004 and May of 2004 and 2005, and 225 MW from November 2003 through April 2004 and from November 2004 through April 2005, by means of firm call options.

ACC Financing Orders

On April 4, 2003, the ACC issued the Financing Order authorizing 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 (the "APS Loan"), subject to the following principal conditions:

- any debt issued by APS pursuant to the order must be unsecured;
- the APS Loan must be callable and secured by the PWEC Dedicated Assets;
- the APS Loan must bear interest at a rate equal to 264 basis points above the interest rate on APS 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 APS' cost of capital as a result of the transaction (such as from a decline in bond rating) will be excluded from future rate cases;
- APS must maintain a common equity ratio of at least forty percent and may not pay common dividends if such payment would reduce its 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 temporarily 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, 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 SNWA pursuant to an agreement between SNWA and Pinnacle West Energy.

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. On June 13, 2003, APS submitted its report on these matters to the ACC Staff.

On May 12, 2003, APS issued $500 million of debt pursuant to the Financing Order and made a $500 million loan to Pinnacle West Energy. Pinnacle West Energy distributed the net proceeds of that loan to us to fund the repayment of a portion of the debt we incurred to finance the construction of the PWEC Dedicated Assets. See Note 4.

On November 22, 2002, the ACC issued an order (the "Interim Financing Order") approving APS' request to permit APS to (a) make short-term advances to Pinnacle West in the form of an interaffiliate 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 September 30, 2003, there were no borrowings outstanding under this financing arrangement. This authority will expire on December 4, 2003.

APS General Rate Case and Retail Rate Adjustment Mechanisms

As noted above, on June 27, 2003, APS filed a general rate case with the ACC and requested a $175.1 million, or 9.8%, increase in its annual retail electricity revenues, to become effective July 1, 2004. In this rate case, APS updated its cost of service and rate design.

Major Components of the Request The major reasons for the request include:

- complying with the provisions of the 1999 Settlement Agreement;

- incorporating significant increases in fuel and purchased power costs, including results of purchases through the ACC's Track B procurement process;

- recognizing changes in APS' cost of service, cost allocation and rate design;
- obtaining rate recognition of the PWEC Dedicated Assets;
- recovering $234 million written off by APS as a result of the 1999 Settlement Agreement; and
- recovering restructuring and compliance costs associated with the ACC's Rules.

Requested Rate Increase The requested rate increase totals $175.1 million, or 9.8%, and is comprised of the following items (dollars in millions):

	Annual Revenue	Percent
Increase in base rates	$166.8	9.3%
Rules compliance charge	8.3	0.5%
Total increase	$175.1	9.8%

Test Year The filing is based on an adjusted historical test year ended December 31, 2002.

Cost of Capital The proposed weighted average cost of capital for the test year ended December 31, 2002 is 8.67%, including an 11.5% return on equity.

Rate Base The request is based on a rate base of $4.2 billion, calculated using Original Cost Less Depreciation ("OCLD") methodology. The OCLD rate base approximates the ACC-jurisdictional portion of the net book value of utility plant, net of accumulated depreciation and deferred taxes, as of December 31, 2002, except as set forth below.

The requested rate base includes the PWEC Dedicated Assets, with a total combined capacity of approximately 1,800 MW. These assets were included at their estimated July 1, 2004 net book value. Upon approval of the request, the PWEC Dedicated Assets would be transferred to APS from Pinnacle West Energy.

The filing also includes calculated amounts for Fair Value Rate Base and Replacement Cost New Depreciated ("RCND") rate base. The ACC is required by the Arizona Constitution to make a finding of Fair Value Rate Base, which has traditionally been defined by the ACC as the arithmetic average of OCLD rate base and RCND rate base.

Recovery of Previous $234 Million Write-Off The request includes recovery, over a fifteen year period, of the write-off of $234 million pretax of regulatory assets by APS as a result of the 1999 Settlement Agreement. See "1999 Settlement Agreement" above.

Estimated Timeline APS has asked the ACC to approve the requested rate increase by July 1, 2004. On August 15, 2003, the ACC issued a procedural schedule setting a hearing date on the application of April 7, 2004. We assume that the ACC will make a decision in this general rate case by the end of 2004.

The general rate case also addresses the implementation of rate adjustment mechanisms that were the subject of ACC hearings in April 2003. The rate adjustment mechanisms, which were authorized as a result of the 1999 Settlement Agreement, would allow APS to recover several types of costs, the most significant of which are power supply costs (fuel and purchased power costs) and costs associated with complying with the Rules.

On November 4, 2003, the ACC approved the issuance of an order which authorizes a rate adjustment mechanism allowing APS to recover changes in purchased power costs (but not changes in fuel costs) incurred after July 1, 2004. The other rate adjustment mechanisms authorized in the 1999 Settlement Agreement (such as the costs associated with complying with the ACC electric competition rules) were also tentatively approved for subsequent implementation in the general rate case. The provisions of this order will not become effective until there is a final order in the general rate case, and the ACC further reserved the right to amend, modify or reconsider, in its entirety, this November 4 order during the rate case.

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 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. On April 28, 2003, the FERC Staff issued an additional white paper on the proposed Standard Market Design. The white paper discusses several policy changes to the proposed Standard Market Design, including a greater emphasis on flexibility for regional needs. The FERC invited comments on the white paper, but has not yet set a due date for filing comments. We 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 and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' 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.

6. Nuclear Insurance

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 $300 million 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, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $101 million, subject to an annual limit of $10 million per incident. Based on APS' interest in the three Palo Verde units, APS' maximum potential assessment per incident for all three units is approximately $88 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. APS has 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.

7. Business Segments

We have three principal business segments (determined by products, 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 generation, transmission and distribution;

- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading and APS Energy Services' commodity-related energy services. In early 2003, we moved our marketing and trading division from Pinnacle West to APS for future marketing and trading activities (existing wholesale contracts remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy; and

- our real estate segment, which consists of SunCor's real estate development and investment activities.

The amounts in our other segment include activities principally related to El Dorado's investment in NAC (see Note 12), as well as the parent company and other subsidiaries. Financial data for the Company's business segments follows (dollars in millions):

	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002	Twelve Months Ended September 30, 2003	Twelve Months Ended September 30, 2002
Operating Revenues:						
Regulated electricity	$ 694	$ 719	$ 1,586	$ 1,597	$ 2,002	$ 2,033
Marketing and trading	155	87	485	213	598	230
Real estate	75	44	173	127	247	189
Other	23	21	64	28	98	34
Total	$ 947	$ 871	$ 2,308	$ 1,965	$ 2,945	$ 2,486
Net Income (Loss):						
Regulated electricity	$ 107	$ 88	$ 155	$ 185	$ 140	$ 222
Marketing and trading [(a)]	(5)	24	12	49	(42)	46
Real estate [(b)]	6	(1)	17	9	27	10
Other	2	(10)	7	(13)	(14)	(12)
Total	$ 110	$ 101	$ 191	$ 230	$ 111	$ 266

(a) We recorded a $66 million after tax charge as of October 1, 2002 for the cumulative effect of a change in accounting for trading activities, for the early adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities."

(b) Real estate net income includes income from discontinued operations (net of income taxes) in the following amounts: $7 million for the nine months ended September 30, 2003, $7 million for the nine months ended September 30, 2002, $9 million for the twelve months ended September 30, 2003, and $7 million for the twelve months ended September 30, 2002. See Note 19 for further discussion of our real estate activities.

	As of September 30, 2003	As of December 31, 2002
Assets:		
Regulated electricity	$8,302	$7,585
Marketing and trading	329	414
Real estate	451	504
Other	31	36
Total	$9,113	$8,539

8. Accounting Matters

In August 2003, the EITF reached a consensus on EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in EITF Issue No. 02-3." EITF 03-11 addresses whether realized gains and losses should be shown gross or net in the income statement for contracts that are not held for trading purposes but are derivatives subject to SFAS No. 133. EITF 03-11 is effective for us on October 1, 2003.

We are currently evaluating the impacts of this new guidance on our financial statements. We believe EITF 03-11 may result in net reporting of certain of our derivative transactions. This change will reduce revenues and purchased power expense but will have no effect on our net income. Further, the new guidance may reduce cash flow hedge accounting for certain of our derivative transactions, which could result in increased volatility of net income. Because of varying interpretations, an electric industry group has requested that the FASB clarify the guidance related to cash flow hedge accounting.

In April 2003, the FASB issued SFAS No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities.” This statement amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under SFAS No. 133. The provisions of SFAS No. 149 that relate to previously issued guidance for the implementation of SFAS No. 133 for derivatives should continue to be applied in accordance with the effective dates of the original implementation guidance. In general, other provisions are applied prospectively to contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The impact of this standard was immaterial to our financial statements for the period ended September 30, 2003. However, it may result in more contracts being marked to market through earnings in the future.

In June 2003, the FASB’s Derivatives Implementation Group (DIG) issued DIG Issue C20, “Scope Exceptions: Interpretation of the Meaning of “Not Clearly and Closely Related’ in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature.” To qualify for a normal purchases and sales scope exception under SFAS No. 133, the pricing in a contract must be clearly and closely related to the item being purchased or sold. DIG Issue C20 provides guidance on the clearly and closely related criteria and supercedes previous guidance. The new rules allow the use of broad-based market indicators in certain circumstances.

DIG Issue C20 is effective for us on October 1, 2003. It is to be applied prospectively to existing and future contracts. A special transition adjustment may be required in certain circumstances. While we continue to evaluate this new guidance, we currently do not expect DIG Issue C20 to have a material impact on our financial statements.

In May 2003, the FASB ratified EITF 01-8, “Determining Whether an Arrangement Contains a Lease.” This issue provides guidance for determining whether an arrangement contains a lease that is within the scope of SFAS No. 13, “Accounting for Leases.” Under EITF 01-8, an arrangement contains a lease if the specific property, plant or equipment has been explicitly or implicitly identified and the arrangement conveys to the purchaser the right to use the property, plant or equipment as defined in this issue. For us, the new guidance was effective for arrangements committed to or modified after June 30, 2003. The impact of this guidance was immaterial to our financial statements for the period ended September 30, 2003.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." This statement requires that an issuer classify certain financial instruments, which were previously classified as equity, as liabilities (or assets in some circumstances). The adoption of this standard did not impact our financial statements for the period ended September 30, 2003.

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. For us, EITF 00-21 was effective for revenue arrangements entered into after June 30, 2003. The impact of this guidance was immaterial to our financial statements for the period ended September 30, 2003.

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. We are waiting for further guidance from the FASB and the AICPA on the timing of the final guidance.

See the following Notes for information about other accounting standards:

- Note 9 for a new interpretation (FIN No. 46) related to VIEs;
- Note 10 for an EITF issue (EITF 02-3) related to accounting for energy trading contracts;
- Note 13 for a new accounting standard (SFAS No. 143) on asset retirement obligations;
- Note 15 for a new accounting standard (SFAS No. 148) on stock-based compensation; and
- Note 17 for a new interpretation (FIN No. 45) on guarantees.

9. 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. For us, FIN No. 46 is effective immediately for any VIE created after January 31, 2003 and is effective October 1, 2003 for VIEs created before February 1, 2003. We currently do not expect FIN No. 46 to have a material impact on our financial statements.

In 1986, APS 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. While we continue to evaluate the guidance, we currently do not expect that we will be required to consolidate the Palo Verde SPEs under FIN No. 46.

APS is exposed to losses under the Palo Verde sale-leaseback agreements upon the occurrence of certain events that APS does 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), APS 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 September 30, 2003, APS would have been required to assume approximately $268 million of debt and pay the equity participants approximately $200 million.

10. Derivative Instruments and Energy Trading Activities

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. 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 adopted EITF 02-3 guidance for all contracts in the fourth quarter of 2002. Accordingly in 2002, we recorded a $66 million after tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Contracts that do not meet the definition of a derivative are 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 Condensed Consolidated Statements of Income on a net basis. Derivative instruments used for non-trading activities are accounted for in accordance with SFAS No. 133.

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. See Note 8 for additional information regarding gross or net presentation (EITF 03-11).

The mark-to-market value of derivative instruments related to our risk management and trading activities are presented in two categories, consistent with our business segments:

- Marketing and Trading — both non-trading and trading derivative instruments of our competitive business segment; and

- Regulated Electricity — non-trading derivative instruments that hedge our purchases and sales of electricity and fuel for APS' Native Load requirements of our regulated electricity business segment.

The changes in derivative fair value of our regulated electricity positions included in the Condensed Consolidated Statements of Income for the three, nine and twelve months ended September 30, 2003 and 2002 are comprised of the following (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2003	2002	2003	2002	2003	2002
Gains on the ineffective portion of derivatives qualifying for hedge accounting (a)	$ 1,069	$ 42	$ 8,176	$ 1,965	$ 17,408	$ 1,657
Gains (losses) from the discontinuance of cash flow hedges	—	—	—	(45)	(8,776)	546
Losses from non-hedge derivatives	(7,077)	(5,513)	(6,236)	(7,092)	(3,467)	(7,516)
Prior period mark-to-market losses (gains) realized upon delivery of commodities	(4,494)	376	(39)	6,398	1,568	5,986
Total pretax gain (loss)	$(10,502)	$ (5,095)	$ 1,901	$ 1,226	$ 6,733	$ 673

(a) Time value component of options excluded from assessment of hedge effectiveness.

As of September 30, 2003, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions is approximately five years. During the twelve months ending September 30, 2004, we estimate that a net loss of $7 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.

The following table summarizes our assets and liabilities from risk management and trading activities at September 30, 2003 and December 31, 2002 (dollars in thousands):

September 30, 2003

	Current Assets (a)	Investments (a)	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Mark-to-Market:					
Marketing and Trading	$52,442	$124,546	$(39,178)	$(61,687)	$ 76,123
Regulated Electricity	31,834	4,557	(46,917)	(7,869)	(18,395)
Emission Allowances – at cost	—	27,847	—	(24,892)	2,955
Total	$84,276	$156,950	$(86,095)	$(94,448)	$ 60,683

(a) We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 39% of our $241 million of risk management and trading assets as of September 30, 2003.

December 31, 2002

	Current Assets (b)	Investments (b)	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Mark-to-Market:					
Marketing and Trading (c)	$ 61,142	$121,189	$ (50,510)	$ (74,841)	$ 56,980
Regulated Electricity	41,522	6,971	(60,819)	(36,678)	(49,004)
Emission allowances – at cost	—	63,594	—	(36,381)	27,213
Total	$102,664	$191,754	$(111,329)	$(147,900)	$ 35,189

(b) We have risk management and trading contracts with many counterparties, including a counterparty for which a worst case exposure represented approximately 12% of our $294 million of risk management and trading assets as of December 31, 2002.

(c) Certain assets and liabilities have been reclassified on a gross basis by counterparty. The net asset/(liability) remains the same.

Cash or collateral may be required to serve as collateral against our open positions on certain energy-related contracts. Collateral provided to counterparties is $1 million at

September 30, 2003 and $5 million at December 31, 2002 and is included in investments and other assets on the Condensed Consolidated Balance Sheet. Collateral provided to us by counterparties is $9 million at September 30, 2003 and $22 million at December 31, 2002 and is included in other long-term liabilities on the Condensed Consolidated Balance Sheet.

11. Comprehensive Income

Components of comprehensive income for the three, nine and twelve months ended September 30, 2003 and 2002, are as follows (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2003	2002	2003	2002	2003	2002
Net income	$110,048	$100,916	$191,488	$230,038	$110,858	$265,844
Other comprehensive income (loss):						
Minimum pension liability adjustment, net of tax	—	—	—	(1,835)	(68,463)	(2,801)
Unrealized gain (loss) on derivative instruments, net of tax (a)	(3,704)	1,446	43,927	29,658	58,208	29,460
Reclassification of realized (gain) loss to income, net of tax (b)	(4,378)	2,364	(8,219)	4,090	(12,669)	7,298
Total other comprehensive income (loss)	(8,082)	3,810	35,708	31,913	(22,924)	33,957
Comprehensive income	$101,966	$104,726	$227,196	$261,951	$ 87,934	$299,801

(a) These amounts primarily include unrealized gains and losses on contracts used to hedge our forecasted electricity and gas requirements to serve Native Load.

(b) These amounts primarily include the reclassification of unrealized gains and losses to realized for contracted commodities delivered during the period.

12. Commitments and Contingencies

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 CAISO 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.

APS was a seller and a purchaser in the California markets at issue, and to the extent that refunds are ordered, APS 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 are required to submit necessary data to the FERC, after which a technical conference will be held. Finalization of refund calculations is expected by the end of 2003. Subsequent to the foregoing refund decision by the FERC, the California parties filed a request for rehearing asking the FERC to expand the time period and transactions covered by the refund proceeding and provide for approximately $3 billion in additional refunds relating to sales by all sellers in the California markets. APS does not anticipate material changes in its exposure and still believes, subject to the finalization of the revised proxy prices, that it 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 of January 1, 2000 through June 20, 2001. Parties submitted additional evidence and proposed findings, which the FERC continues to consider. On a parallel track, in March 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 the 2000 to 2001 time period, including APS, may potentially have been involved in arbitrage transactions that allegedly violated certain provisions of the CAISO tariff. The report also recommended that the FERC issue an order to show cause why these transactions did not violate the CAISO tariff with potential disgorgement of any unjust profits.

On June 25, 2003, the FERC issued an order finding that certain identified entities appear to have potentially participated in activities that constitute gaming and/or anomalous market behavior in violation of the CAISO’s and PX’s tariffs during the period of January 1, 2000 through June 20, 2001. The FERC directed the CAISO, within 21 days of the date of the order to provide the identified entities with all of the specific transaction data for each of the specified potential gaming practices, and directed the identified entities to file responses within 45 days thereafter, absent a settlement. The FERC also established a hearing proceeding to be held before an ALJ for the identified entities to show cause, why they should not be found to have engaged in gaming practices in violation of the CAISO and PX tariffs. APS was named as an identified entity in this order because of evidence of possible use of “paper trading” (the buy back of ancillary services) and “false import” (ricochet or megawatt laundering) strategies. Based on its review of the allegations, as outlined in the terms of the order, APS believes that it was not improperly engaged in any of the identified gaming practices. On October 29, 2003, the FERC trial staff filed a motion to dismiss the alleged claims against APS.

Also in June 2003, the FERC initiated an investigation of all bids in the CAISO and PX markets above $250 per MWh during the period of May 1, 2000 through October 1, 2000. The FERC Office of Market Oversight and Investigations has issued data requests and is required to report back to the FERC by year-end 2003. Although APS bid over $250 per MWh during the time period in question, APS believes that its bids were not improper.

With regard to the Pacific Northwest, the FERC, in 2001, ordered an evidentiary proceeding to discuss and evaluate possible refunds. 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. On December 19, 2002, the FERC opened a new discovery period to permit the parties to offer additional evidence for the period of January 1, 2000 through June 20, 2001. Additional evidence was submitted in March 2003. In June 2003, the FERC issued a final order terminating this proceeding without refunds. Certain parties have sought rehearing of the FERC’s final order.

Although the FERC has not calculated the specific refund amounts due in California, concluded newly established investigations of behavior in the Western markets, or ruled upon the requests for rehearing in the Pacific Northwest cases, we do not expect that the resolution of these issues will have a material adverse impact on our financial position, results of operations 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 CAISO. PG&E filed for bankruptcy protection in 2001.

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. Based on our evaluations, we previously reserved $10 million before income taxes for our credit exposure related to the California energy situation, $5 million of which was recorded in the fourth quarter of 2000 and $5 million of which was recorded in the first quarter of 2001. Our evaluations took into consideration our range of exposure of approximately zero to $38 million before income taxes and review of likely recovery rates in bankruptcy situations.

In the second quarter of 2002, PG&E filed its Modified Second Amended Disclosure Statement and the CPUC filed its Alternative Plan of Reorganization. Both plans generally indicated that PG&E would, at the close of bankruptcy proceedings, be able to pay in full all outstanding, undisputed debts. As a result of these developments, we estimated the probable range of our total exposure to be approximately zero to $27 million before income taxes, and our best estimate of the probable loss is now approximately $6 million before income taxes. Consequently, we reversed $4 million of the $10 million reserve in the second quarter of 2002. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us, our subsidiaries or the regional energy market in general.

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 CAISO markets, including APS, attempting to expand those matters to such other participants. APS has not yet filed a responsive pleading in the matter, but APS believes the claims by Reliant and Duke as they relate to APS are without merit.

APS was 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 APS 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 us, 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 APS 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.

The Citizens Power Service Agreement

APS has a long history of contractual relations with Citizens relating to providing electricity and ancillary services to the utility in Arizona owned by Citizens. Under the current power sale agreement, we provide for deliveries of electricity and ancillary services through May 31, 2008. On August 11, 2003, Citizens sold its Arizona utility to a subsidiary of UniSource, UNS Electric, Inc. (“UNS Electric”). In connection with that sale, the above referenced power sale agreement was amended and assigned to UNS Electric. The Company does not expect any potential claims relating to the agreement and/or any prior related agreements, including as to any claims previously raised by Citizens, to have a material adverse impact on its financial statements.

El Dorado's Investment in NAC

Through our unregulated wholly-owned subsidiary, El Dorado, we own a majority interest in NAC, a company that develops, markets and contracts for the manufacture of cask designs for spent nuclear fuel storage and transportation. Prior to the third quarter of 2002, our investment in NAC was accounted for under the equity method and our share of NAC's earnings and losses was recorded in other income or expense in our Condensed Consolidated Statements of Income. Beginning in the third quarter of 2002, we fully consolidated NAC's financial statements after acquiring a controlling interest in NAC as a result of increased voting representation on NAC's Board of Directors. During the second and third quarters of 2002, we recorded cumulative losses of approximately $21 million before tax ($13 million after tax) related to NAC, primarily as a result of expected losses under contracts with two customers.

We recorded additional NAC losses of approximately $38 million before tax ($23 million after tax) in the fourth quarter of 2002, the substantial majority of which related to the termination of a contract with one of the customers referenced above. As a result, in 2002, we recorded NAC losses of approximately $59 million before tax ($35 million after tax). We reversed $5 million of loss reserves in the first quarter of 2003 related to NAC's settlement of pending litigation and arbitration relating to the contract termination. We believe we have reserved our exposure with respect to NAC's contracts in all material respects. We do not expect material losses for the year 2003 related to NAC.

Natural Gas Supply

APS and Pinnacle West Energy purchase the majority of their natural gas requirements for their gas-fired plants under contracts with a number of natural gas suppliers. Effective September 1, 2003, APS' and Pinnacle West Energy's natural gas supply is transported pursuant to a firm, contract demand service agreement with El Paso Natural Gas Company. Pursuant to the terms of a comprehensive settlement entered into in 1996, the rates charged for transportation are subject to a 10-year rate moratorium extending through December 31, 2005.

Prior to September 1, 2003, APS' and Pinnacle West Energy's natural gas supply was transported pursuant to a firm, full requirements transportation service agreement. On July 9, 2003 the FERC issued an order that altered the contractual obligations and the rights of parties to the 1996 settlement by requiring all firm, full requirements contract holders to convert to contract demand service agreements effective September 1, 2003. This required conversion has imposed additional limitations on the former full requirements contract holders' ability to nominate firm transportation capacity. In order for APS and Pinnacle West Energy to meet their natural gas supply and capacity requirements, they must make market purchases, which we expect to increase costs by approximately $5 million per year for natural gas supply and by approximately $14 million per year for capacity, both of which amounts are reflected in the Company's budgets. APS and Pinnacle West Energy have sought appellate review of the FERC's July 9 order on the grounds that the FERC decision to abrogate the full requirements contracts is arbitrary and capricious and is not supported by substantial evidence. *Arizona Public Service Company and Pinnacle West Energy Corporation v. Federal Energy Regulatory Commission* , United States Court of Appeals for the District of Columbia Circuit, No. 03-1209. This petition for review was consolidated with a petition filed by the ACC and other full requirements contract holders. *Arizona Corporation Commission et al v. Federal Energy Regulatory Commission* , United States Court of Appeals for the District of Columbia Circuit, No. 03-1206. We are continuing to analyze the market to determine the most favorable source and method of meeting our natural gas requirements.

13. Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, “Accounting for Asset Retirement Obligations.” SFAS No. 143 provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. The standard requires that these liabilities be recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. Prior to January 1, 2003, we accrued asset retirement obligations over the life of the related asset through depreciation expense.

APS has asset retirement obligations for its Palo Verde nuclear facilities and certain other generation, transmission and distribution assets. The Palo Verde asset retirement obligation primarily relates to final plant decommissioning. This obligation is based on the NRC’s requirements for disposal of radiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation asset retirement obligations primarily relate to requirements for removing portions of those plants at the end of the plant life or lease term. Some of APS’ transmission and distribution assets have asset retirement obligations because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the asset retirement obligation related to such distribution and transmission assets. The asset retirement obligations associated with our non-regulated assets are immaterial.

On January 1, 2003 and in accordance with SFAS No. 143, APS recorded a liability of $219 million for its 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, APS recorded a net regulatory liability of $40 million for the asset retirement obligations related to its regulated assets. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. APS believes it can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 143. The adoption of SFAS No. 143 did not have a material impact on our net income for the quarter or nine months ended September 30, 2003.

In accordance with SFAS No. 71, APS will continue to accrue for removal costs for its regulated assets, even if there is no legal obligation for removal. At September 30, 2003, accumulated depreciation shown on our Condensed Consolidated Balance Sheets included approximately $384 million of estimated future removal costs that are not considered legal obligations.

The following schedule shows the change in our asset retirement obligations during the nine-month period ended September 30, 2003 (dollars in millions):

Balance at January 1, 2003	$ 219
Changes attributable to:	
Liabilities incurred	—
Liabilities settled	—
Accretion expense	12
Estimated cash flow revisions	—
Balance at September 30, 2003	$ 231

The following schedule shows the change in our pro forma liability for the years ended December 31, 2002 and 2001, as if we had recorded an asset retirement obligation based on the guidance in SFAS No. 143 (dollars in millions):

	2002	2001
Balance at beginning of year	$ 204	$ 190
Accretion expense	15	14
Balance at end of year	$ 219	$ 204

The pro forma effects on net income for 2002 and 2001 are immaterial.

To fund the costs APS expects to incur to decommission the plant, APS established external decommissioning trusts in accordance with NRC regulations. APS invests the trust funds primarily in fixed income securities and domestic stock and classifies them as available for sale. The following table shows the cost and fair value of APS' nuclear decommissioning trust fund assets which are on the Condensed Consolidated Balance Sheets at September 30, 2003 and December 31, 2002 (dollars in millions):

	September 30, 2003	December 31, 2002
Trust fund assets – at cost		
Fixed income securities	$ 118	$ 113
Domestic stock	75	68
Total	$ 193	$ 181
Trust fund assets – at fair value		
Fixed income securities	$ 127	$ 117
Domestic stock	100	77
Total	$ 227	$ 194

14. Intangible Assets

The Company's gross intangible assets (which are primarily software) were $247 million at September 30, 2003 and $214 million at December 31, 2002. The increase in gross intangible assets is primarily new software. The related accumulated amortization was $126 million at September 30, 2003 and $104 million at December 31, 2002. Amortization expense for the three months ended September 30 was $8 million in 2003 and $6 million in 2002. Amortization expense for the nine months ended September 30 was $21 million in 2003 and $14 million in 2002. Amortization expense for the twelve months ended September 30 was $28 million in 2003 and $20 million in 2002. Estimated amortization expense on existing intangible assets over the next five years is $29 million in 2003, $30 million in 2004, $29 million in 2005, $25 million in 2006 and $18 million in 2007.

15. Stock-Based Compensation

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." In accordance with the transition requirements of SFAS No. 123, as amended by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure," 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, stock compensation expense and earnings per share for the three, nine and twelve months ended September 30, 2003 and 2002 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 September 30, 2003 (dollars in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2003	2002	2003	2002	2003	2002
Net income, as reported	$110,048	$100,916	$191,488	$230,038	$110,858	$265,844
Add- Stock compensation expense included in reported net income (net of tax)	396	212	894	212	1,003	212
Deduct- Total stock compensation expense determined under fair value method (net of tax)	838	729	2,221	1,762	2,847	2,233
Pro forma net income	$109,606	$100,399	$190,161	$228,488	$109,014	$263,823

Earnings per share – basic:						
As reported	$1.21	$1.19	$2.10	$2.71	$1.24	$3.14
Pro forma	$1.20	$1.18	$2.08	$2.70	$1.21	$3.11
Earnings per share – diluted:						
As reported	$1.20	$1.19	$2.09	$2.71	$1.23	$3.13
Pro forma	$1.20	$1.18	$2.08	$2.69	$1.21	$3.11

16. Other Income and Other Expense

The following table provides detail of other income and other expense for the three, nine and twelve months ended September 30, 2003 and 2002 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2003	2002	2003	2002	2003	2002
Other income:						
Environmental insurance recovery	$ —	$ —	$ —	$ —	$ —	$ 1,402
Investment gains – net	2,248	185	3,617	627	1,739	1,550
Interest income	1,809	1,880	3,572	3,815	4,196	6,096
SunCor joint venture earnings	331	123	4,863	3,406	8,812	4,424
Miscellaneous	1,145	838	1,834	2,291	1,844	4,257
Total other income	$ 5,533	$ 3,026	$ 13,886	$ 10,139	$ 16,591	$ 17,729
Other expense:						
Investment losses – net (a)	$ —	$ (4,137)	$ —	$ (8,371)	$ —	$(10,415)
Non-operating costs – SunCor	—	—	—	—	—	(2,500)
Non-operating costs (b)	(4,539)	(4,834)	(12,284)	(15,037)	(16,677)	(21,422)
Miscellaneous	(1,252)	(1,742)	(2,795)	(3,379)	(3,204)	(5,919)
Total other expense	$ (5,791)	$(10,713)	$(15,079)	$(26,787)	$(19,881)	$(40,256)

(a) Primarily related to El Dorado’s investment in NAC in 2002 (see Note 12).

(b) As defined by the FERC, includes below-the-line non-operating utility costs (primarily community relations).

17. Guarantees

On January 1, 2003 we adopted FIN No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN No. 45 elaborates on the disclosures to be made by a guarantor in its financial statements about its obligations under certain guarantees. It also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The disclosure provisions are effective for the year ended December 31, 2002. The initial recognition and measurement provisions of FIN No. 45 are effective on a prospective basis to guarantees issued or modified after December 31, 2002.

We have issued parental guarantees and letters of credit and obtained surety bonds on behalf of our unregulated subsidiaries. Our parental guarantees related to Pinnacle West Energy primarily consist of equipment and performance guarantees related to our generation construction program, transmission service guarantees for West Phoenix Units 4 and 5 and long-term service agreement guarantees for new power plants. Our credit support instruments enable APS Energy Services to provide commodity energy and energy-related products and enable El Dorado to support the activities of NAC. SunCor has a debt guarantee on behalf of an affiliated joint venture. Non-performance or payment under the original contract by our unregulated subsidiaries would require us to perform under the guarantee or surety bond. No liability is currently recorded on the Condensed Consolidated Balance Sheets related to Pinnacle West's guarantees on behalf of its subsidiaries. Our guarantees have no recourse (except NAC) or collateral provisions to allow us to recover amounts paid under the guarantee. The amounts and approximate terms of our guarantees and surety bonds for each subsidiary at September 30, 2003 are as follows (dollars in millions):

	Guarantees		Surety Bonds		Letters of Credit	
	Amount	Term (in years)	Amount	Term (in years)	Amount	Term (in years)
Parental:						
Pinnacle West Energy	$ 102	1 to 2	$ —		$ 36	1 to 2
APS Energy Services	73	1 to 2	35	2	—	
El Dorado (all NAC)	42	1 to 3	—		—	
SunCor guarantees	38	1	—		—	
Pinnacle West letter of credit	—		—		4	1
Total	$ 255		$ 35		$ 40	

At September 30, 2003, we had entered into approximately $36 million of letters of credit which support various construction agreements. These letters of credit expire in 2003 and 2004. We have approximately $4 million of letters of credit related to workers' compensation expiring in 2004. 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.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At September 30, 2003, approximately $200 million of letters of credit were outstanding to support existing pollution control bonds of approximately $200 million.

The letters of credit are available to fund the payment of principal and interest of such debt obligations. These letters of credit have expiration dates in 2004 and 2005. APS has also entered into approximately $109 million of letters of credit to support certain equity lessors in the Palo Verde sale-leaseback transactions. These letters of credit expire in 2005. Additionally, APS has approximately $5 million of letters of credit related to counterparty collateral requirements expiring in 2003. APS intends to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required.

In conjunction with our financing agreements, including our Palo Verde sale-leaseback transactions, we generally provide indemnifications relating to liabilities arising from or related to the agreements, except for certain limited exceptions depending on the particular agreement. APS has 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.

18. Earnings Per Share

The following table presents earnings per weighted average common share outstanding for the three, nine and twelve months ended September 30, 2003 and 2002:

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2003	2002	2003	2002	2003	2002
Basic earnings per share:						
Income from continuing operations	$1.20	$1.19	$2.02	$2.63	$ 1.87	$3.05
Income from discontinued operations	0.01	—	0.08	0.08	0.10	0.09
Cumulative effect of a change in accounting for trading activities	—	—	—	—	(0.73)	—
Earnings per share – basic	$1.21	$1.19	$2.10	$2.71	$ 1.24	$3.14
Diluted earnings per share:						
Income from continuing operations	$1.20	$1.19	$2.02	$2.63	$ 1.87	$3.05
Income from discontinued operations	—	—	0.07	0.08	0.09	0.08
Cumulative effect of a change in accounting for trading activities	—	—	—	—	(0.73)	—
Earnings per share – diluted	$1.20	$1.19	$2.09	$2.71	$ 1.23	$3.13

The following table reconciles weighted-average common shares outstanding – basic to weighted-average common shares outstanding – diluted that are used in the earnings per share calculation in the Condensed Consolidated Statements of Income for the three, nine and twelve months ended September 30, 2003 and 2002 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2003	2002	2003	2002	2003	2002
Weighted-average common shares outstanding – basic	91,271	84,768	91,262	84,768	89,760	84,746
Dilutive shares	196	29	170	91	159	105
Weighted-average common shares outstanding – diluted	91,467	84,797	91,432	84,859	89,919	84,851

Options to purchase 1,784,168 shares for the three-month period ended September 30, 2003, 2,021,928 shares for the nine-month period ended September 30, 2003 and 2,038,158 shares for the twelve-month period ended September 30, 2003 were outstanding but were not included in the computation of earnings per share because the options’ exercise prices were greater than the average market price of the common shares. Options to purchase shares of common stock that were not included in the computation of diluted earnings per share were 2,118,994 shares for the three months ended September 30, 2002, 1,281,721 shares for the nine months ended September 30, 2002 and 1,284,063 shares for the twelve months ended September 30, 2002.

19. Real Estate Activities – Discontinued Operations

On January 1, 2002, we adopted SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets.” Among other guidance, SFAS No. 144 prescribes accounting for discontinued operations and defines certain activities as discontinued operations.

In the first quarter of 2003, SunCor sold its water utility company, which resulted in an after tax gain of $5 million ($8 million pretax). The amounts of the gain on the sale and operating income of the water utility company in the current and prior periods are classified as discontinued operations on our Condensed Consolidated Statements of Income.

In the second quarter of 2002, SunCor sold a retail center, but maintained a significant continuing involvement through a management contract. In the first quarter of 2003, this management contract was canceled. As a result, an after tax gain of $6 million ($10 million pretax) was reported related to the 2002 sale. This after tax gain and operating income related to this property have been reclassified as discontinued operations on our Condensed Consolidated Statements of Income. The income from discontinued operations in the nine and twelve months ended September 30, 2002 primarily reflects this sale.

The following chart provides a summary of SunCor’s earnings (after income taxes) for the three, nine and twelve months ended September 30, 2003 and the comparable prior year periods (dollars in millions):

	Three Months Ended September 30,		**Nine Months Ended September 30,**		**Twelve Months Ended September 30,**	
	2003	**2002**	**2003**	**2002**	**2003**	**2002**
Income (loss) from continuing operations	$ 6	$ (1)	$ 10	$ 2	$ 18	$ 3
Income from discontinued operations	—	—	7	7	9	7
Net income (loss)	$ 6	$ (1)	$ 17	$ 9	$ 27	$ 10

The following table provides SunCor’s revenue and income before income taxes related to properties classified as discontinued operations for the three, nine and twelve months ended September 30, 2003 and the comparable prior year periods (dollars in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2003	2002	2003	2002	2003	2002
Revenue	$ 2	$ 2	$ 59	$ 28	$ 66	$ 28
Income before taxes	1	—	11	12	14	12

The following tables provide the amounts related to properties of discontinued operations which were reclassified to assets and liabilities held for sale on the Consolidated Balance Sheets as of December 31, 2002 (dollars in thousands):

	Assets
Real estate investments-net	$39,849
Other	2,490
Real estate assets held for sale	$42,339

	Liabilities
Customer deposits	$13,648
Long-term debt less current maturities	12,454
Other	2,753
Real estate liabilities held for sale	$28,855

For the years 2001 and 2000, items requiring discontinued operations reporting were immaterial. In addition, see note 7 for information related to the real estate segment.

20. Allowance for Funds Used During Construction Accounting Policy

In the third quarter of 2003, APS returned to the allowance for funds used during construction (“AFUDC”) method of capitalizing interest and equity costs associated with construction projects in a regulated utility. This is consistent with APS returning to a vertically integrated utility, as evidenced by APS’ recent general rate case filing, which includes the request for rate recognition of generation assets. Previously, APS capitalized interest in accordance with SFAS No. 34, “Capitalization of Interest Cost.” AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction of utility plant. Although AFUDC both increases the plant balance and results in higher current earnings during the construction period, AFUDC is realized in future revenues through depreciation provisions included in rates. AFUDC has been calculated using a composite rate of 8.51% in 2003. APS compounds AFUDC semiannually and ceases to accrue AFUDC when construction is completed and the property is placed in service. This change increased earnings by $8 million in the third quarter of 2003.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Introduction

In this Item, we explain the results of operations, general financial condition and outlook for Pinnacle West and our subsidiaries: APS, Pinnacle West Energy, APS Energy Services, SunCor and El Dorado, including:

- the changes in our earnings for the three, nine and twelve months ended September 30, 2003 and 2002;
- our capital needs, liquidity and capital resources;
- our business outlook and major factors that affect our financial outlook (see Note 5 to the Condensed Consolidated Financial Statements and "Business Outlook" below); and
- our management of market risks.

We suggest this section be read along with the 2002 10-K. Throughout this Item, we refer to specific "Notes" in the Notes to Condensed Consolidated Financial Statements in this report. These Notes add further details to the discussion. Operating statistics for the three, nine and twelve months ended September 30, 2003 and 2002 are available on our website (www.pinnaclewest.com) and in our Current Report on Form 8-K dated September 30, 2003.

Overview of Our Business

The Company owns all of the outstanding common stock of APS. APS is 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 one-half of the Phoenix metropolitan area. Electricity is delivered through a distribution system owned by APS. APS also generates, sells and delivers electricity to wholesale customers in the western United States. APS does not distribute any products. The marketing and trading segment sells, in the wholesale market, APS and Pinnacle West Energy generation output that is not needed for APS' Native Load, which includes loads for retail customers and traditional cost-of-service wholesale customers. In early 2003, we moved our marketing and trading division from Pinnacle West to APS for future marketing and trading activities (existing wholesale contracts remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy.

Our other major subsidiaries are:

- Pinnacle West Energy, through which we conduct our competitive electricity generation operations;

- APS Energy Services, which provides competitive commodity-related energy services (such as direct access commodity contracts, energy procurement and energy supply consultation) and energy-related products and services (such as energy master planning, energy use consultation and facility audits, cogeneration analysis and installation and project management) to commercial, industrial and institutional retail customers in the western United States;

- SunCor, a developer of residential, commercial and industrial real estate projects in Arizona, New Mexico and Utah; and

- El Dorado, which owns a majority interest in NAC (specializing in spent nuclear fuel technology) and holds miscellaneous small investments, including interests in Arizona community-based ventures.

Earnings Contributions By Subsidiary And Business Segment

We have three principal business segments (determined by products, 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 generation, transmission and distribution;

- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading and APS Energy Services' commodity-related energy services; and

- our real estate segment, which consists of SunCor's real estate development and investment activities.

The following tables summarize net income and segment details for the three, nine and twelve months ended September 30, 2003 and the comparable prior year periods for Pinnacle West and each of our subsidiaries (dollars in millions):

Three months ended September 30,	Total		Regulated Electricity		Marketing and Trading		Real Estate (a)		Other (b)	
	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002
Arizona Public Service (APS) (c)	$100	$ 87	$104	$86	$ (4)	$ 1	$—	$—	$—	$ —
Pinnacle West Energy (c)	3	10	3	10	—	—	—	—	—	—
APS Energy Services (d)	1	7	—	—	—	7	—	—	1	—
SunCor	6	(1)	—	—	—	—	6	(1)	—	—
El Dorado (d)	1	(15)	—	—	—	—	—	—	1	(15)
Parent company (d)	(1)	13	—	(8)	(1)	16	—	—	—	5
Net income (loss)	$110	$101	$107	$88	$ (5)	$24	$ 6	$ (1)	$ 2	$(10)

Nine months ended September 30,	Total		Regulated Electricity		Marketing and Trading		Real Estate (a)		Other (b)	
	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002
Arizona Public Service (APS) (c)	$159	$183	$156	$182	$ 3	$ 1	$—	$—	$—	$ —
Pinnacle West Energy (c)	11	12	12	12	(1)	—	—	—	—	—
APS Energy Services (d)	13	20	—	—	10	18	—	—	3	2
SunCor	10	2	—	—	—	—	10	2	—	—
El Dorado (d)	6	(18)	—	—	—	—	—	—	6	(18)
Parent company (d)	(15)	24	(13)	(9)	—	30	—	—	(2)	3
Income (loss) from continuing operations	184	223	155	185	12	49	10	2	7	(13)
Income from discontinued operations – net of tax	7	7	—	—	—	—	7	7	—	—
Net income (loss)	$191	$230	$155	$185	$12	$49	$17	$ 9	$ 7	$(13)

Twelve months ended September 30,	Total		Regulated Electricity		Marketing and Trading		Real Estate (a)		Other (b)	
	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002
Arizona Public Service (APS) (c)	$176	$222	$173	$218	$ 3	$ 4	$—	$—	$ —	$ —
Pinnacle West Energy (c) (e)	(20)	15	(22)	15	2	—	—	—	—	—
APS Energy Services (d)	21	21	—	—	15	20	—	—	6	1
SunCor	18	3	—	—	—	—	18	3	—	—
El Dorado (d)	(31)	(19)	—	—	—	—	—	—	(31)	(19)
Parent company (d)	4	17	(11)	(11)	4	22	—	—	11	6
Income (loss) from continuing operations	168	259	140	222	24	46	18	3	(14)	(12)
Income from discontinued operations – net of tax	9	7	—	—	—	—	9	7	—	—
Cumulative effect of change in accounting - net of tax (f)	(66)	—	—	—	(66)	—	—	—	—	—
Net income (loss)	$111	$266	$140	$222	$(42)	$46	$27	$10	$(14)	$(12)

(a) See “Real Estate Activities” discussion below and Note 19.

(b) The “Other” segment primarily includes activities related to El Dorado’s investment in NAC. We recorded pretax losses of $16 million in the three months ended September 30, 2002 and $21 million in the nine and twelve months ended September 30, 2002, primarily related to NAC contracts with two customers. In the twelve months ended September 30, 2003, we recorded an additional $33 million in pretax losses related to these same contracts, partially offset by a contract settlement. See Note 12.

(c) Consistent with APS’ October 2001 ACC filing, APS entered into contracts with its affiliates to buy power through June 2003. The contracts reflected prices based on the fully-dispatchable dedication of the Pinnacle West Energy generating assets to APS’ Native Load customers (customers receiving power under traditional cost-based rate regulation). Beginning July 1, 2003, under the ACC Track B Order, APS was required to solicit bids for certain estimated capacity and energy requirements. Pinnacle West Energy bid on and entered into a contract to supply most of these purchase power requirements in summer months through September 2006. See “Track B Order” in Note 5 for more information.

(d) APS Energy Services’ net income prior to 2003 and El Dorado’s net income (loss) are primarily reported before income taxes. The income tax expense or benefit for these subsidiaries was recorded at the parent company.

(e) In the fourth quarter of 2002, Pinnacle West Energy recorded a charge related to the cancellation of Redhawk Units 3 and 4 of approximately $30 million after income taxes ($49 million pretax).

(f) We recorded a $66 million after-tax charge as of October 1, 2002 for the cumulative effect of a change in accounting for trading activities, for the early adoption of EITF 02-3.

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 our marketing and trading segment, gross margin refers to electric operating revenues less purchased power and fuel costs. Our real estate segment gross margin refers to real estate revenues less real estate operations costs of SunCor. Other gross margin refers to other operating revenues less other operating expenses, which primarily includes El Dorado's investment in NAC, which we began consolidating in our financial statements in July 2002. Other gross margin also includes amounts related to APS Energy Services' energy consulting services.

Consistent with APS returning to a vertically integrated utility, as evidenced by APS' recent general rate case filing, which includes the request for rate recognition of generation assets, APS has also returned to the Allowance for Funds Used During Construction ("AFUDC") method, which is a more traditional method of capitalizing interest and equity costs associated with construction projects in a regulated utility. This change increased earnings by $8 million in the third quarter of 2003. See Note 20.

Operating Results – Three-month period ended September 30, 2003 compared with Three-month period ended September 30, 2002

Our consolidated net income for the three months ended September 30, 2003 was $110 million compared with $101 million for the prior period. The $9 million increase in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment — Net income increased $19 million primarily due to higher retail sales related to customer growth and favorable weather effects; lower operating costs primarily related to severance costs recorded in 2002; higher capitalized construction finance costs related to APS' return to the AFUDC method of capitalizing such costs; an income tax benefit recorded in 2003; and lower regulatory asset amortization, consistent with the comprehensive settlement agreement related to the implementation of retail electric competition (the "1999 Settlement Agreement"). These favorable factors were partially offset by higher replacement power costs from plant outages due to more unplanned outages and higher market prices; higher prices for hedged gas and purchased power; a retail electricity price reduction that was effective July 1, 2003; and higher pension and other costs.

- Marketing and Trading Segment – Net income decreased $29 million, reflecting the effects of lower market liquidity in the wholesale power markets in the western United States on our marketing and trading activities.

- Real Estate Segment – Net income increased $7 million because of increased land and home sales.

- Other Segment – Net income increased $12 million, primarily due to the absence of NAC losses in 2003 (see Note 12).

Additional details on the major factors that increased (decreased) income from continuing operations before income taxes and net income are contained in the table below (dollars in millions).

	Increase (Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Higher replacement power costs from plant outages due to more unplanned outages and higher market prices	$(22)	$(13)
Increased purchased power and fuel costs primarily due to higher prices for hedged gas and purchased power	(19)	(11)
Retail electricity price reduction effective July 1, 2003	(9)	(5)
Higher retail sales primarily due to customer growth, excluding weather effects	22	13
Decreased purchased power costs due to new power plants in service	12	7
Effects of weather on retail sales	7	4
Miscellaneous items, net	6	3
Net decrease in regulated electricity segment gross margin	(3)	(2)
Marketing and trading segment gross margin:		
Lower mark-to-market gains for future delivery due to lower market liquidity resulting in lower volumes and margins	(26)	(16)
Lower realized margins on wholesale sales due to lower unit margins and lower volumes	(13)	(8)
Lower unit margins on higher competitive retail sales in California by APS Energy Services	(5)	(3)
Miscellaneous items, net	(2)	(1)
Net decrease in marketing and trading segment gross margin	(46)	(28)
Net decrease in regulated electricity and marketing and trading segments’ gross margins	(49)	(30)
Higher income primarily related to the absence of NAC losses in 2003	17	10
Higher real estate segment contribution primarily due to increased land and home sales at SunCor	12	7
Operations and maintenance expense:		
Severance costs recorded in 2002	26	16
Increased pension and other benefit costs	(7)	(4)
Costs for new power plants in service	(4)	(2)
Other items, net	(4)	(2)
Depreciation and amortization:		
Primarily related to increased delivery and other assets	(5)	(3)
Depreciation related to new power plant in service	(4)	(2)
Decreased regulatory asset amortization	7	4
Higher income resulting from APS’ return to the AFUDC method of capitalizing construction finance costs	5	8
Income tax credits related to prior years	—	7
Net decrease in income from continuing operations before income taxes	$ (6)	
Net increase in net income		$ 9

The increase in operating and interest costs related to new power plants placed in service by Pinnacle West Energy, net of purchased power savings and increased gross margin from generation sales other than Native Load, totaled approximately $3 million after income taxes in the three months ended September 30, 2003 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were $25 million lower in the three months ended September 30, 2003, compared with the same period in the prior year primarily as a result of:

- a $72 million decrease related to retail load hedge management wholesale sales primarily as a result of lower sales volumes;
- a $9 million decrease in retail revenues related to a reduction in retail electricity prices;
- a $33 million increase in retail revenues related to customer growth, excluding weather effects;
- a $14 million increase in retail revenues related to weather; and
- a $9 million net increase due to miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $67 million higher in the three months ended September 30, 2003, compared with the same period in the prior year primarily as a result of:

- $77 million of higher realized wholesale revenues primarily due to higher prices;
- a $13 million increase from higher competitive retail sales in California by APS Energy Services, partially offset by lower prices;
- $24 million in lower mark-to-market gains for future delivery primarily as a result of lower market liquidity; and
- a $1 million net increase due to miscellaneous factors.

Operating Results – Nine-month period ended September 30, 2003 compared with Nine-month period ended September 30, 2002

Our consolidated net income for the nine months ended September 30, 2003 was $191 million compared with $230 million for the prior year. Both periods include income from discontinued operations related to our real estate segment (see "Real Estate Activities" below). The $39 million decrease in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment — Net income decreased $30 million primarily because of higher replacement power costs from plant outages due to higher market prices and more unplanned outages; higher costs related to new power plants, net of related gross margin benefits; higher prices for hedged gas and purchased power; two retail electricity price reductions; higher pension and other benefit costs; and higher depreciation expense related to increased delivery assets. These negative factors were partially offset by higher retail sales primarily due to customer growth; lower operating costs primarily related to severance costs recorded in 2002; lower regulatory asset amortization, consistent with the 1999 Settlement Agreement; higher income related to APS' return to the AFUDC method of capitalizing construction finance costs; and an income tax benefit recorded in 2003.

- Marketing and Trading Segment — Net income decreased $37 million, reflecting lower market liquidity in the wholesale power markets in the western United States, partially offset by higher revenues related to structured contracts from prior years (including the effects of the adoption of EITF 02-3 in the fourth quarter of 2002).

- Real Estate Segment — Net income increased $8 million primarily due to increased home and land sales.

- Other Segment — Net income increased $20 million primarily due to the absence of NAC losses in 2003 and the current-period settlement of an NAC contract dispute (see Note 12).

Additional details on the major factors that increased (decreased) income from continuing operations before income taxes and net income are contained in the table below (dollars in millions).

	Increase (Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Higher replacement power costs from plant outages due to higher market prices and more unplanned outages	$(35)	$(21)
Increased purchased power and fuel costs primarily due to higher prices for hedged gas and purchased power	(24)	(14)
Retail electricity price reductions effective July 1, 2002 and July 1, 2003	(21)	(13)
Higher retail sales volumes due to customer growth, excluding weather effects	45	27
Decreased purchased power costs due to new power plants in service	16	10
Miscellaneous factors, net	(2)	(2)
Net decrease in regulated electricity segment gross margin	(21)	(13)
Marketing and trading segment gross margin:		
Lower mark-to-market gains for future delivery due to lower market liquidity	(60)	(36)
Lower realized margins on wholesale sales primarily due to lower unit margins, partially offset by higher volumes	(23)	(14)
Higher revenues related to structured contracts from prior years (including the effects of the adoption of EITF 02-3)	13	8
Increased competitive retail sales in California by APS Energy Services	5	3
Miscellaneous factors, net	(1)	(1)
Net decrease in marketing and trading segment gross margin	(66)	(40)
Net decrease in regulated electricity and marketing and trading segments’ gross margins	(87)	(53)
Higher income primarily related to the absence of NAC losses in 2003 and NAC’s settlement of a contract dispute recorded in the first quarter of 2003	28	17
Higher real estate segment contribution primarily due to increased home and land sales at SunCor	12	8
Higher interest expense on higher debt balances and lower capitalized interest primarily related to new power plants in service	(20)	(12)
Higher income resulting from APS’ return to the AFUDC method of capitalizing construction finance costs	5	8
Operations and maintenance expense:		
Increased pension and other benefit costs	(20)	(12)
Costs for new power plants in service	(14)	(8)
Severance costs recorded in 2002	26	16
Other items, net	(10)	(7)
Depreciation and amortization:		
Primarily related to increased delivery and other assets	(19)	(11)
Depreciation related to new power plants in service	(16)	(10)
Decreased regulatory asset amortization	22	13
Income tax credits related to prior years	—	7
Miscellaneous factors, net	7	5
Net decrease in income from continuing operations before income taxes	$(86)	
Net decrease in net income		$(39)

The increase in operating and interest costs related to new power plants placed in service by Pinnacle West Energy, net of purchased power savings and increased gross margin from generation sales other than Native Load, totaled approximately $17 million after income taxes in the nine months ended September 30, 2003 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were $10 million lower in the nine months ended September 30, 2003, compared with the same period in the prior year primarily as a result of:

- a $72 million decrease related to retail load hedge management wholesale sales primarily as a result of lower sales volumes;
- a $21 million decrease in retail revenues related to reductions in retail electricity prices;
- a $69 million increase in retail revenues related to customer growth, excluding weather effects;
- a $6 million increase related to traditional wholesale sales as a result of higher sales volumes and higher prices; and
- an $8 million net increase due to miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $272 million higher in the nine months ended September 30, 2003, compared with the same period in the prior year primarily as a result of:

- $217 million of higher realized wholesale revenues primarily due to higher volumes, including revenues related to structured contracts from prior years (including the effects of the adoption of EITF 02-3);
- a $61 million increase from higher competitive retail sales in California by APS Energy Services;
- a $54 million increase from generation sales other than Native Load primarily due to higher prices and higher sales volumes, including sales from new power plants in service; and
- $60 million in lower mark-to-market gains for future delivery primarily as a result of lower market liquidity and higher price volatility.

Operating Results – Twelve-month period ended September 30, 2003 compared with Twelve-month period ended September 30, 2002

Our consolidated net income for the twelve months ended September 30, 2003 was $111 million compared with $266 million for the prior year. Both periods include income from discontinued operations related to our real estate segment (see “Real Estate Activities” below). The $155 million decrease in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment — Net income decreased $82 million primarily due to higher operations and maintenance costs related to the cancellation of Redhawk Units 3 and 4 and increased pension and other benefits; higher prices for hedged gas and purchased power; higher costs related to new power plants, net of related gross margin benefits; higher replacement power costs from plant outages due to higher market prices and more unplanned outages; two retail electricity price reductions; and higher depreciation expense related to increased delivery assets. These negative factors were partially offset by higher retail sales primarily due to customer growth; lower regulatory asset amortization, consistent with the 1999 Settlement Agreement; lower operating costs primarily related to severance costs recorded in 2002; 2001 charges related to purchase power contracts with Enron; higher income related to APS’ return to the AFUDC method of capitalizing construction finance costs; and an income tax benefit recorded in 2003.

- Marketing and Trading Segment — Net income decreased $88 million, reflecting a charge for the cumulative effect of a change in accounting for trading activities at the time of the early adoption of EITF 02-3 on October 1, 2002; and lower market liquidity in the wholesale power markets in the western United States. These negative factors were partially offset by higher revenues related to structured contracts from prior years (including the effects of the adoption of EITF 02-3); higher competitive retail sales in California by APS Energy Services; and fourth quarter 2001 charges related to Enron and its affiliates.

- Real Estate Segment — Net income increased $17 million primarily due to increased land and home sales.

Additional details on the major factors that increased (decreased) income from continuing operations and net income are contained in the table below (dollars in millions).

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	Increase (Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Increased purchased power and fuel costs primarily due to higher prices for hedged gas and purchased power	$ (40)	$ (24)
Higher replacement power costs from plant outages due to higher market prices and more unplanned outages	(31)	(19)
Retail electricity price reductions effective July 1, 2002 and July 1, 2003	(27)	(16)
Effects of milder weather on retail sales	(6)	(4)
Higher retail sales volumes due to customer growth, excluding weather effects	46	28
Decreased purchased power costs due to new power plants in service	16	10
2001 charges related to purchased power contracts with Enron	13	8
Miscellaneous factors, net	9	5
Net decrease in regulated electricity segment gross margin	(20)	(12)
Marketing and trading segment gross margin:		
Lower mark-to-market gains for future delivery due to lower market liquidity	(64)	(38)
Lower realized margins on wholesale sales primarily due to lower unit margins, partially offset by higher volumes	(22)	(13)
Higher revenues related to structured contracts from prior years (including the effects of the adoption of EITF 02-3)	20	12
Increased competitive retail sales in California by APS Energy Services	12	7
Change in prior period mark-to-market value related to trading with Enron	8	5
Increased generation sales other than Native Load primarily due to higher sales volumes, including sales from new power plants in service, partially offset by lower unit margins	5	3
Net decrease in marketing and trading segment gross margin	(41)	(24)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(61)	(36)
Operations and maintenance expense:		
Cancellation of Redhawk Units 3 and 4 in the fourth quarter of 2002	(47)	(28)
Increased pension and other benefit costs	(21)	(13)
Severance costs recorded in 2002	15	9
Costs for new power plants in service	(15)	(9)
Other items, net	(22)	(13)
Lower income primarily related to NAC losses	(9)	(5)
Higher interest expense and lower capitalized interest primarily related to new power plants in service	(27)	(16)
Higher income resulting from APS' return to the AFUDC method of capitalizing construction finance costs	5	8
Depreciation and amortization:		
Depreciation related to new power plants in service	(22)	(13)
Primarily related to increased delivery and other assets	(25)	(15)
Decreased regulatory asset amortization	29	17
Higher taxes other than income taxes due to increased property taxes on higher property balances	(10)	(6)
Higher real estate segment contribution primarily due to higher home and land sales, equity earnings in joint ventures and decreased miscellaneous expenses	25	16
Higher APS Energy Services non-commodity margin	6	4
Miscellaneous items, net	3	3
Income tax credits related to prior years	—	7
Net decrease in income from continuing operations	$(176)	(90)
Increase in income from discontinued operations related to SunCor – net of income tax (see "Real Estate Activities" below and Note 19)		1
Decrease due to cumulative effect of a change in accounting for trading activities due to the adoption of EITF 02-3 – net of income tax		(66)
Net decrease in net income		$(155)

The increase in operating and interest costs related to new power plants placed in service by Pinnacle West Energy, net of purchased power savings and increased gross margin from generation sales other than Native Load, totaled approximately $21 million after income taxes in the twelve months ended September 30, 2003 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were $30 million lower in the twelve months ended September 30, 2003, compared with the same period in the prior year primarily as a result of:

- an $88 million decrease related to retail load hedge management wholesale sales primarily as a result of lower prices and lower sales volumes;
- a $27 million decrease in retail revenues related to reductions in retail electricity prices;
- a $9 million decrease in retail revenues related to milder weather;
- a $70 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- a $7 million increase related to traditional wholesale sales as a result of higher prices and higher sales volumes; and
- a $17 million net increase due to miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $368 million higher in the twelve months ended September 30, 2003, compared with the same period in the prior year primarily as a result of:

- $256 million of higher realized wholesale revenues primarily due to higher volumes, partially offset by lower prices, including revenues related to structured contracts from prior years (including the effects of the adoption of EITF 02-3);
- an $88 million increase from higher competitive retail sales in California by APS Energy Services;
- an $80 million increase from generation sales other than Native Load primarily due to higher sales volumes and higher prices, including sales from new power plants in service;
- an $8 million increase due to the fourth quarter 2001 write-off of prior-period mark-to-market value related to trading with Enron and its affiliates; and

- $64 million in lower mark-to-market gains for future delivery primarily as a result of lower market liquidity and lower price volatility.

Real Estate Activities

As discussed in our 2002 10-K, we have undertaken an aggressive effort to accelerate asset sales activities to approximately double SunCor's annual earnings in 2003 to 2005 compared with the $19 million in earnings recorded in 2002.

Certain components of SunCor's real estate sales activities, which are included in the real estate segment, are required to be reported as discontinued operations on our Condensed Consolidated Statements of Income in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Among other guidance, SFAS No. 144 prescribes accounting for discontinued operations and defines certain activities as discontinued operations. We adopted SFAS No. 144 effective January 1, 2002 and determined that activities that would have required discontinued operations reporting in 2002, 2001 and 2000 were immaterial. We currently estimate that 15% to 30% of SunCor's net income in 2003 will be reported in discontinued operations; however, this ultimately depends on the specific properties sold.

In the first quarter of 2003, SunCor sold its water utility company, which resulted in an after tax gain of $5 million ($8 million pretax). The amounts of the gain on the sale and operating income of the water utility company in the current and prior periods are classified as discontinued operations on our Condensed Consolidated Statements of Income.

In the second quarter of 2002, SunCor sold a retail center, but maintained a significant continuing involvement through a management contract. In the first quarter of 2003, this management contract was canceled. As a result, an after tax gain of $6 million ($10 million pretax) was reported related to the 2002 sale. This after tax gain and operating income related to this property have been reclassified as discontinued operations on our Condensed Consolidated Statements of Income. The income from discontinued operations in the nine and twelve months ended September 30, 2002 primarily reflects this sale.

The following chart provides a summary of SunCor's earnings (after income taxes) for the three, nine and twelve months ended September 30, 2003 and the comparable prior year periods (dollars in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2003	2002	2003	2002	2003	2002
Income (loss) from continuing operations	$ 6	$ (1)	$10	$2	$18	$ 3
Income from discontinued operations	—	—	7	7	9	7
Net income (loss)	$ 6	$ (1)	$17	$9	$27	$10

The following table provides SunCor's revenue and income before income taxes related to properties classified as discontinued operations for the three, nine and twelve months ended September 30, 2003 and the comparable prior year periods (dollars in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2003	2002	2003	2002	2003	2002
Revenue	$2	$ 2	$59	$28	$66	$28
Income before taxes	1	—	11	12	14	12

The following tables provide the amounts related to properties of discontinued operations which were reclassified to assets and liabilities held for sale on the Consolidated Balance Sheets as of December 31, 2002 (dollars in thousands):

	Assets
Real estate investments-net	$39,849
Other	2,490
Real estate assets held for sale	$42,339

	Liabilities
Customer deposits	$13,648
Long-term debt less current maturities	12,454
Other	2,753
Real estate liabilities held for sale	$28,855

Liquidity and Capital Resources

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the nine months ended September 30, 2003 and estimated capital expenditures for the next three years (dollars in millions):

	Actual	Estimated		
	Nine Months Ended September 30,	Twelve Months Ended December 31,		
	2003	2003	2004	2005
APS:				
Delivery	$215	$280	$307	$386
Generation (a)	86	132	108	159
Other	5	5	2	2
Subtotal	306	417	417	547
Pinnacle West Energy (a) (b)	176	236	61	24
SunCor (c)	45	64	47	27
Other (d)	11	17	11	18
Total	$538	$734	$536	$616

(a) As discussed in Note 5 under "APS General Rate Case and Retail Rate Adjustment Mechanisms," as part of its 2003 general rate case, APS requested rate base treatment of the PWEC Dedicated Assets.

(b) See "Capital Resources and Cash Requirements – Pinnacle West Energy" below for further discussion of Pinnacle West Energy's generation construction program. These amounts do not include an expected reimbursement in 2004 by SNWA of about $100 million (plus capitalized interest), based upon SNWA's agreement to purchase a 25% interest in the Silverhawk project at that time.

(c) Consists primarily of capital expenditures for land development and retail and office building construction reflected in "Change in real estate investments" on the Condensed Consolidated Statements of Cash Flows.

(d) Primarily related to the parent company and APS Energy Services.

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, APS began several major transmission projects in 2001, with additional major projects scheduled to begin over the next several years. These projects are periodic in nature and are driven by strong regional customer growth. APS expects to spend about $100 million on major transmission projects during the 2003 to 2005 time frame, and these amounts are included in "APS-Delivery" in the table above.

Generation capital expenditures are comprised of various improvements for APS' 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 2007 time frame. Our portion of steam generator expenditures for Units 1, 2 and 3 is approximately $209 million, of which approximately $157 million will be spent from 2003 through 2008. In 2003 through 2005, $109 million of the costs are included in the generation capital expenditures table above and would be funded with internally-generated cash or external financings.

Capital Resources and Cash Requirements

Contractual Obligations The following table summarizes actual contractual payments made during the nine months ended September 30, 2003 and estimated contractual commitments for the next five years and thereafter as of September 30, 2003 (dollars in millions):

	Actual	Estimated					
	Nine Months Ended September 30,	Twelve Months Ended December 31,					
	2003	2003	2004	2005	2006	2007	Thereafter
Long-term debt payments:							
APS	$ 87	$ 87	$205	$400	$ 84	$ —	$1,931
Pinnacle West	250	275	215	—	300	—	—
SunCor	63	63	130	—	3	—	7
El Dorado	1	1	1	1	—	—	—
Total long-term debt payments	401	426	551	401	387	—	1,938
Capital lease payments	3	5	3	3	2	1	4
Operating lease payments	50	71	68	65	63	63	478
Purchase power and fuel commitments	223	280	125	63	66	53	525
Total contractual commitments	$677	$782	$747	$532	$518	$117	$2,945

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. For us, FIN No. 46 is effective immediately for any VIE created after January 31, 2003 and is effective October 1, 2003 for VIEs created before February 1, 2003. We currently do not expect FIN No. 46 to have a material impact on our financial statements.

In 1986, APS 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. While we continue to evaluate the guidance, we currently do not expect that we will be required to consolidate the Palo Verde SPEs under FIN No. 46.

APS is exposed to losses under the Palo Verde sale-leaseback agreements upon the occurrence of certain events that APS does 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), APS 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 September 30, 2003, APS would have been required to assume approximately $268 million of debt and pay the equity participants approximately $200 million.

Guarantees

We and certain of our subsidiaries have issued guarantees and letters of credit in support of our unregulated businesses. We have also obtained surety bonds on behalf of APS Energy Services. We have not recorded any liability on our Condensed Consolidated Balance Sheets with respect to these obligations. See Note 17 for additional information regarding guarantees.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of November 12, 2003 are shown below and are considered to be “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 Pinnacle West’s or APS’ securities and serve to increase those companies’ cost of and access to capital.

	Moody's	Standard & Poor's
Pinnacle West		
Senior unsecured	Baa2	BBB-
Commercial paper	P-2	A-2
APS		
Senior secured	A3	A-
Senior unsecured	Baa1	BBB
Secured lease obligation bonds	Baa2	BBB
Commercial paper	P-2	A-2
Outlook	Stable	Stable

Debt Provisions

Pinnacle West’s and APS’ significant debt covenants related to their respective financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test (as defined in the agreements). Pinnacle West and APS are in compliance with such covenants and each anticipates it will continue to meet all the significant covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65% for both the Company and APS. At September 30, 2003, the ratios were approximately 54% for the parent company and 54% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for both the Company and APS. The coverages are approximately 4 times for the parent company, 4 times for the APS bank agreements and 14 times for the APS mortgage indenture at September 30, 2003. 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.

Neither Pinnacle West’s nor APS’ financing agreements 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, Pinnacle West and/or APS may be subject to increased interest costs under certain financing agreements.

All of Pinnacle West’s bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these agreements if Pinnacle West or APS were to default under other agreements. All of APS’ bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under other agreements. Pinnacle West’s and APS’ 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.

Pinnacle West (Parent Company)

Our primary cash needs are for dividends to our shareholders; equity infusions into our subsidiaries, primarily Pinnacle West Energy; and interest payments and optional and mandatory repayments of principal on our long-term debt (see the table above for our contractual requirements, including our debt repayment obligations, but excluding optional repayments). The level of our common dividends and future dividend growth will be dependent on a number of factors including, but not limited to, payout ratio trends, free cash flow and financial market conditions.

Our primary sources of cash are dividends from APS, external financings and cash distributions from our other subsidiaries, primarily SunCor. For the years 2000 through 2002, total dividends from APS were $510 million and total distributions from SunCor were $33 million. We expect SunCor to make cash distributions to the parent company of $80 to $100 million annually in 2003 through 2005 due to anticipated accelerated asset sales activity. As discussed in Note 5, APS must maintain a common equity ratio of at least 40% and may not pay common dividends if the payment would reduce its common equity below that threshold. As defined in the Financing Order, common equity ratio is common equity divided by common equity plus long-term debt, including current maturities of long-term debt. At September 30, 2003, APS' common equity ratio was approximately 46%.

On November 22, 2002, the ACC issued the Interim Financing Order, which permits APS 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 September 30, 2003, there were no borrowings outstanding under this financing arrangement. This authority will expire December 4, 2003.

On May 12, 2003, APS issued $500 million of debt as follows: $300 million aggregate principal amount of its 4.650% Notes due 2015 and $200 million aggregate principal amount of its 5.625% Notes due 2033. Also on May 12, 2003, APS made a $500 million loan to Pinnacle West Energy, and Pinnacle West Energy distributed the net proceeds of that loan to us to fund our repayment of a portion of the debt incurred to finance the construction of the PWEC Dedicated Assets. See "ACC Financing Orders" in Note 5 for additional information. With Pinnacle West Energy's distribution to us, on May 12, 2003, we repaid the outstanding balance ($167 million) under a credit facility. We used a portion of the remaining proceeds to redeem our $250 million Floating Rate Notes due 2003 on June 2, 2003 and to repay other short-term debt.

On November 12, 2003, we issued $165 million of our Floating Rate Senior Notes due 2005. The bonds are callable at par beginning November 1, 2004. The primary use of this financing is to ultimately repay at maturity our $215 million 4.5% Notes due February 2004.

As part of a multi-employer pension plan sponsored by Pinnacle West, we contribute 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 our pension obligation. We elected to contribute cash to our pension plan in each of the last five years; our minimum required contributions during each of those years was zero. Specifically, we contributed $73 million for 2002 ($46 million of which was contributed in June 2003), $24 million for 2001, $44 million for 2000 ($20 million of which was contributed in 2001), $25 million for 1999 and $14 million for 1998. APS and other subsidiaries fund their share of the pension contribution, of which APS represents approximately 90% of the total funding amounts described above. The assets in the plan are mostly domestic common stocks, bonds and real estate. Future year contribution amounts are dependent on fund performance and fund valuation assumptions.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "Business Outlook - Regulatory Matters" below and Notes 4 and 5 for discussion of the $500 million financing arrangement between APS and Pinnacle West Energy authorized by the ACC pursuant to the Financing Order and APS' related issuance of $500 million of debt. See "Pinnacle West (Parent Company)" above and Note 5 for discussion of a $125 million interim financing arrangement between APS and Pinnacle West.

APS pays for its capital requirements with cash from operations and, to the extent necessary, external financings. APS has historically used cash from operations to pay dividends to Pinnacle West.

On April 7, 2003, APS redeemed approximately $33 million of its First Mortgage Bonds, 8% Series due 2025, and on August 1, 2003, APS redeemed approximately $54 million of its First Mortgage Bonds, 7.25% Series due 2023.

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

Pinnacle West Energy

The costs of Pinnacle West Energy's construction of 2,360 MW of generating capacity from 2000 through 2004 are expected to be about $1.4 billion, of which $1.3 billion has been incurred through September 30, 2003. This does not reflect the proceeds from an anticipated sale in 2004 to SNWA of a 25% interest in the plant, which would equal about $100 million (plus capitalized interest) of Pinnacle West Energy's cumulative capital expenditures in the Silverhawk project. SNWA has agreed to purchase a 25% interest in the project upon completion. Such purchase is subject to an appropriation of funds by SNWA. Pinnacle West Energy's capital requirements are currently funded through capital infusions from Pinnacle West, which finances those infusions through debt and equity financings and internally-generated cash. See the capital expenditures table above for actual capital expenditures in the nine months ended September 30, 2003 and projected capital expenditures for the next three years.

Pinnacle West Energy's generation facilities consist of the following:

- A 650 MW combined cycle expansion of the West Phoenix Power Plant in Phoenix. The 120 MW West Phoenix Unit 4 began commercial operation in

June 2001. The 530 MW West Phoenix Unit 5 began commercial operation in July 2003.

- The 570 MW Silverhawk combined-cycle plant 20 miles north of Las Vegas, Nevada. Construction of the plant began in August 2002, with an expected commercial operation date of mid-2004. Pinnacle West Energy has signed an agreement with Las Vegas-based SNWA whereby SNWA has agreed to purchase a 25% interest in the project upon completion, subject to an appropriation of funds by SNWA for approximately $100 million (plus capitalized interest).

- The Redhawk Power Plant which consists of two 530 MW combined cycle units located near Palo Verde. Commercial operation began in July 2002.

- An 80 MW simple-cycle power plant at Saguaro in Southern Arizona. Commercial operation began in July 2002.

In August 2003, Pinnacle West Energy sold its 50% interest in Copper Eagle Gas Storage, a limited liability company established for the purpose of evaluating and developing an underground natural gas storage facility west of Phoenix, to El Paso Natural Gas Company.

See Notes 4 and 5 and “Pinnacle West (Parent Company)” above for a discussion of the $500 million financing arrangement between APS and Pinnacle West Energy authorized by the ACC pursuant to the Financing Order.

Other Subsidiaries

During the past three years, SunCor funded its cash requirements with cash from operations and its own external financings. SunCor’s capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the capital expenditures table above for actual capital expenditures in the nine months ended September 30, 2003 and projected capital expenditures through 2005. SunCor expects to fund its capital requirements with cash from operations and external financings.

We expect SunCor to make cash distributions to the parent company of $80 to $100 million annually in 2003 through 2005 due to anticipated accelerated asset sales activity. SunCor has made cash distributions to the parent company in the amount of $33 million through September 30, 2003. See “Real Estate Activities” above and Note 19.

El Dorado funded its cash requirements during the past three years, primarily for NAC in 2002, with cash infused by the parent company and with cash from operations. El Dorado expects minimal capital requirements through 2005.

APS Energy Services’ cash requirements during the past three years were funded with cash infusions from the parent company. APS Energy Services’ capital expenditures and other cash requirements are increasingly funded by operations, with some funding from cash infused by Pinnacle West. See the capital expenditures table above regarding APS

Energy Services' actual capital expenditures for the nine months ended September 30, 2003 and projected capital expenditures through 2005.

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. Our most critical accounting policies include the impacts of regulatory accounting and the determination of the appropriate accounting for our pension and other postretirement benefits, derivatives and mark-to-market accounting. There have been no changes to our critical accounting policies since our 2002 10-K except for the impact of recent accounting pronouncements as discussed in Note 8. See "Critical Accounting Policies" in Item 7 of the 2002 10-K for further details about our critical accounting policies.

Other Accounting Matters

Consistent with APS returning to a vertically integrated utility, as evidenced by APS' recent general rate case filing, which includes the request for rate recognition of generation assets, APS has also returned to the AFUDC method, which is a more traditional method of capitalizing interest and equity costs associated with construction projects in a regulated utility. This change increased earnings by $8 million in the third quarter of 2003. See Note 20 for our AFUDC accounting policy.

On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. See Note 13 for our Asset Retirement Obligation discussion.

Business Outlook

In this section we discuss a number of factors affecting our business outlook.

Regulatory Matters

See Note 5 for a discussion of ACC regulatory matters, including the APS general rate case filed on June 27, 2003.

Wholesale Power Market Conditions

The marketing and trading division focuses primarily on managing APS' purchased power and fuel risks in connection with its costs of serving retail customer demand. We moved this division to APS in early 2003 for future marketing and trading activities (existing wholesale contracts remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting APS' transfer of generating assets to Pinnacle West Energy. Additionally, the marketing and trading division, subject to specified parameters, markets, hedges and trades in electricity, fuels, and emission allowances and credits. Our future earnings will be affected by the strength or weakness of the wholesale power market. The market has suffered a substantial reduction in overall liquidity because there are fewer creditworthy counterparties and because several key participants have exited the market or scaled back their activities. Based on the erosion in the market and on the market outlook, we currently expect contributions from our trading activities (excluding gross margin from generation sales other than Native Load and gross margin attributable to structured transactions originated in years prior to 2003) to be negligible or slightly negative for the years 2003 and 2004.

Generation Construction Plan

See “Liquidity and Capital Resources – Pinnacle West Energy” for information regarding Pinnacle West Energy’s generation construction plan. The planned additional generation is expected to increase revenues, fuel expenses, operating expenses and financing costs.

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 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. Competitive sales of energy and energy-related products and services are made by APS Energy Services in western states that have opened to competitive supply.

Customer Growth Customer growth in APS’ 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 4.0% to 6.0% a year in 2003 through 2005, before the retail effects of weather variations. The customer and sales growth referred to in this paragraph applies to energy delivery customers. Customer growth for the nine-month period ended September 30, 2003 compared with the prior year period was 3.2%.

Retail Rate Changes As part of the 1999 Settlement Agreement, APS agreed to 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%. The final price reduction was implemented July 1, 2003. See “1999 Settlement Agreement” in Note 5 for further information. In addition, the Company has requested a 9.8% retail rate increase to be effective July 1, 2004. See “APS General Rate Case and Retail Rate Adjustment Mechanisms” in Note 5 for further information.

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, new generating plants being placed in service and our hedging program for managing such costs. See “Natural Gas Supply” in Note 12 for more information on fuel costs.

During the third quarter of 2003, we experienced several unplanned baseload generating unit outages, the most significant of which occurred when, on August 2, 2003, the generator on Unit 3 of our Cholla Power Plant failed ("Cholla 3"). Cholla 3 is expected to be out of service until the end of November 2003. In addition, to correct an equipment design defect, the availability of Units 1 and 2 of our Redhawk Power Plant is expected to be substantially restricted for approximately 1.5 months during the fourth quarter of 2003.

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 $36 million before taxes in voluntary severance costs in the second half of 2002.

Depreciation and Amortization Expenses Depreciation and amortization expenses are expected to be affected by net additions to existing utility plant and other property, changes in regulatory asset amortization and our generation construction program. West Phoenix Unit 4 was placed in service in June 2001. Redhawk Units 1 and 2 and the new Saguaro Unit 3 began commercial operations in July 2002. West Phoenix Unit 5 was placed in service in July 2003 and Silverhawk is expected to be in service in mid-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

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 for APS, which currently owns the majority of our property, was 9.7% of assessed value for 2002 and 9.3% for 2001. We expect property taxes to increase primarily due to our generation construction program, as the plants phase-in to the property tax base over a five-year period, and 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 accruing capitalized interest on a project when it is placed in commercial operation. As noted above, we placed new power plants in commercial operation in 2001, 2002 and 2003 and we expect to bring an additional plant on-line in 2004. Interest expense is also affected by interest rates on variable-rate debt and interest rates on the refinancing of the Company's future liquidity needs. In addition, see Note 20 for discussion of AFUDC.

Retail Competition The regulatory developments and legal challenges to the Rules discussed in Note 5 have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

Subsidiaries In the case of SunCor, we are undertaking an aggressive effort to accelerate asset sales activities, which we expect to approximately double SunCor's annual earnings in 2003 to 2005 compared with the $19 million in earnings recorded in 2002. A portion of these sales have been, and additional amounts may be required to be, reported as discontinued operations on the Condensed Consolidated Statements of Income. See "Real Estate Activities" above and Note 19 for further discussion.

The annual earnings contribution from APS Energy Services is expected to be positive over the next several years due primarily to a number of retail electricity contracts in California. APS Energy Services had pretax earnings of $28 million in 2002.

El Dorado's historical results are not necessarily indicative of future performance for El Dorado. In addition, we do not currently expect material losses related to NAC in the future.

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.

Risk Factors

Exhibit 99.1, which is hereby incorporated by reference, contains a discussion of risk factors involving the Company.

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. These forward-looking statements are often identified by words such as "hope," "may," "believe," "anticipate," "plan," "expect," "require," "intend," "assume" and similar words. 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, but are not limited to:

- 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 the outcome of the rate case APS filed with the ACC on June 27, 2003 and the wholesale electric price mitigation plan adopted by the FERC;

- regional economic and market conditions, including the results of litigation and other proceedings resulting from the California energy situation, volatile purchased power and fuel costs and the 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;
- energy usage;
- weather variations affecting local and regional customer energy usage;
- conservation programs;
- power plant performance;
- market prices for electricity and gas;
- the successful completion of our generation construction program;
- regulatory issues associated with generation construction, such as permitting and licensing;
- changes in GAAP;
- 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 (including the interpretation of the subjective and complex accounting rules related to these contracts);
- 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;
- the strength of the real estate market in SunCor’s market areas, which include Arizona, New Mexico and Utah; and
- other uncertainties, all of which are difficult to predict and many of which are beyond our control.

Item 3. 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 our pension plans.

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. Our 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.

We adopted EITF 02-3 guidance for all contracts in the fourth quarter of 2002. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Contracts that do not meet the definition of a derivative are 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 Condensed Consolidated Statements of Income on a net basis. Derivative instruments used for non-trading activities are accounted for in accordance with SFAS No. 133. See Note 10 for details on the change in accounting for energy trading contracts.

Both non-trading and trading derivatives are classified as assets and liabilities from risk management and trading activities in the Condensed Consolidated 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:

- Marketing and Trading — both non-trading and trading derivative instruments of our competitive business segment; and
- Regulated Electricity — non-trading derivative instruments that hedge our purchases and sales of electricity and fuel for APS' Native Load requirements of our regulated electricity business segment.

The following tables show the changes in mark-to-market of our regulated electricity and marketing and trading derivative positions for the nine months ended September 30, 2003 and 2002 (dollars in millions):

	Nine Months Ended September 30, 2003		Nine Months Ended September 30, 2002	
	Regulated Electricity	Marketing and Trading	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at beginning of period	$(49)	$ 57	$(107)	$138
Change in mark-to-market gains (losses) for future period deliveries	(6)	(5)	(7)	55
Changes in cash flow hedges recorded in OCI	29	44	49	—
Ineffective portion of changes in fair value recorded in earnings	8	—	2	—
Mark-to-market losses (gains) realized during the period	—	(20)	9	(34)
Mark-to-market of net positions at end of period	$(18)	$ 76	$ (54)	$159

Since July 1, 2002, the Company has not recognized a dealer profit or unrealized gain or loss at the inception of a derivative unless the fair value of that instrument (in its entirety) is evidenced by quoted market prices or current market transactions. Prior to the change in our policy, we recorded net gains at inception of $10 million in the nine months ended September 30, 2002. These amounts included a reasonable marketing margin. No net gains at inception were recorded in the nine months ended September 30, 2003.

The tables below show the fair value of the regulated electricity and marketing and trading derivative contracts (dollars in millions) at September 30, 2003 by maturities and by the type of valuation that is performed to calculate the fair values. See “Critical Accounting Policies — Mark-to-Market Accounting” in Item 7 of our 2002 10-K for more discussion on our valuation methods.

Regulated Electricity

Source of Fair Value	2003	2004	2005	2006	2007	Years thereafter	Total fair value
Prices actively quoted	$ (7)	$ (9)	$—	$—	$—	$ —	$(16)
Prices provided by other external sources	—	(5)	—	—	—	—	(5)
Prices based on models and other valuation methods	1	1	1	—	—	—	3
Total by maturity	$ (6)	$(13)	$ 1	$—	$—	$ —	$(18)

Marketing and Trading

Source of Fair Value	2003	2004	2005	2006	2007	Years thereafter	Total fair value
Prices actively quoted	$10	$ 30	$(10)	$(10)	$—	$ —	$ 20
Prices provided by other external sources	(9)	(28)	32	34	29	—	58
Prices based on models and other valuation methods	3	14	(5)	(11)	(8)	5	(2)
Total by maturity	$ 4	$ 16	$ 17	$ 13	$21	$ 5	$ 76

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management and trading assets and liabilities included on the Condensed Consolidated Balance Sheets at September 30, 2003 and 2002 (dollars in millions).

Commodity	September 30, 2003 Gain (Loss) Price Up 10%	September 30, 2003 Gain (Loss) Price Down 10%	September 30, 2002 Gain (Loss) Price Up 10%	September 30, 2002 Gain (Loss) Price Down 10%
Mark-to-market changes reported in earnings (a):				
Electricity	$ (2)	$ 2	$ (1)	$ 2
Natural gas	(3)	3	(1)	1
Other	—	—	1	—
Mark-to-market changes reported in OCI (b):				
Electricity	33	(33)	—	—
Natural gas	12	(11)	17	(15)
Total	$40	$(39)	$16	$(12)

(a) These contracts are structured sales activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.

(b) These contracts are hedges of our forecasted purchases of natural gas and electricity. 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 and Counterparty Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 39% of our $241 million of risk management and trading assets as of September 30, 2003. Our risk management process assesses and monitors the financial exposure of these counterparties and all other counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, including the counterparties noted above, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated 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. We also enter into credit default swap instruments to limit our credit risk related to certain counterparties. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See “Critical Accounting Policies – Mark-to-Market Accounting” in Item 7 of our 2002 10-K for more discussion on our valuation methods.

Item 4. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

The Company’s management, with the participation of the Company’s Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness the Company’s disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures as of the end of the period covered by this report have been designed and are functioning effectively to provide reasonable assurance that the information required to be disclosed by the Company in reports filed under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms.

(b) Change in Internal Control over Financial Reporting

No change in the Company’s internal control over financial reporting occurred during the Company’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

See Note 12 of Notes to Condensed Consolidated Financial Statements in Part 1, Item 1 of this report for a discussion of the settlement of the NAC litigation and APS' appeal of a FERC order.

Item 5. Other Information

Construction and Financing Programs

See "Liquidity and Capital Resources" in Part I, Item 2 of this report for a discussion of construction and financing programs of the Company and its subsidiaries.

Regulatory Matters

See Note 5 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of regulatory developments.

Environmental Matters

Superfund

As previously reported, under the terms of a Consent Decree, APS agreed to pay $2.72 million to settle the matter relating to the Indian Bend Wash Superfund Site, South Area. See "Environmental Matters – Superfund" in Part II, Item 5 of the March 2003 10-Q. On August 28, 2003, the United States District Court for the District of Arizona entered the Consent Decree. Pursuant to the Consent Decree, APS paid $2.32 million to the EPA and $400,000 to the Arizona Department of Environmental Quality.

On September 3, 2003, the EPA advised APS that the EPA considers APS to be a "potentially responsible party" in the Motorola 52nd Street Superfund Site, Operable Unit 3 (OU3) in Phoenix, Arizona. APS has facilities that are within this superfund site. The EPA has only recently begun to study the OU3 site. Based on the information to date, APS does not expect this matter to have a material impact on its financial position, results of operations or liquidity.

Water Supply

The Four Corners region, in which the Four Corners power plant is located, has been experiencing drought conditions that may affect the water supply for the plant in 2003 and 2004, as well as later years if adequate moisture is not received in the watershed that supplies the area. See "Environmental Matters – Water Supply" in Item I, Part 1 of the 2002 10-K and in Part II, Item 5 of the June 2003 10-Q. We entered into agreements with various parties to provide backup supplies of water for 2003, if required, and are continuing to work with area stakeholders to implement additional agreements to minimize the effect, if any, on operations of the plant for 2004 and later years. 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 the Four Corners power plant.

Natural Gas Supply

See Note 12 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of a recent FERC ruling.

Regional Transmission Organizations

In December 2002 FERC issued its order on rehearing of the order regarding the WestConnect proposal, and the WestConnect applicants sought further clarification of certain aspects of the rehearing order. See "Regulation and Competition – Regional Transmission Organizations" in Part I, Item 1 of the 2002 10-K. On September 15, 2003, the FERC issued an order granting clarification and rehearing, in part, of its prior orders. In particular, this order approved the use of a physical congestion management scheme, which is used to allocate transmission rights on congested lines, for WestConnect for an initial phase-in period. FERC indicated that the WestConnect utilities and the appropriate regional state advisory committee should develop a market based congestion management scheme for subsequent implementation. APS is now participating in a cost/benefit analysis of implementing WestConnect, and the results of this analysis are expected to be completed in the first quarter of 2004.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Exhibit No.	Description
4.1	Second Supplemental Indenture dated as of November 1, 2003, relating to the issuance of $165,000,000 of the Company's Floating Rate Senior Notes due 2005
12.1	Ratio of Earnings to Fixed Charges
31.1	Certification of William J. Post, the Registrant's principal executive officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Donald E. Brandt, the Registrant's principal financial officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of William J. Post, the Registrant's principal executive officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Donald E. Brandt, the Registrant's principal financial officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	Pinnacle West Risk Factors

In addition, 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. [a]	Date Effective
3.1	Articles of Incorporation restated as of July 29, 1988	19.1 to the Company's September 30, 1988 Form 10-Q Report	1-8962	11-14-88
3.2	Bylaws, amended as of September 18, 2002	3.1 to the Company's September 30, 2002 Form 10-Q Report	1-8962	11-14-02

(b) Reports on Form 8-K

During the quarter ended September 30, 2003, and the period from October 1 through November 14, 2003, we filed the following reports on Form 8-K:

Report dated June 27, 2003 regarding APS' rate request (Item 5 and Item 7).

Report dated June 30, 2003 containing exhibits comprised of financial information, earnings variance explanations and an earnings news release (Item 7 and Item 9).

Report dated September 2, 2003 comprised of slides presented at analysts meetings (Item 7 and Item 9).

Report dated September 30, 2003 containing exhibits comprised of financial information, earnings variance explanations and an earnings news release (Item 7 and Item 9).

Report dated October 6, 2003 regarding earnings outlook and slides presented at analysts and investors meetings (Item 5, Item 7, and Item 9).

Report dated November 5, 2003 containing a financial statement reclassification and relating to the ACC approval of the issuance of a rate adjustment mechanism order. This current Report on Form 8-K includes the consolidated balance sheets of Pinnacle West as of December 31, 2002 and 2001, and the related consolidated statements of income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2002. Schedule II — Valuation and Qualifying Accounts is also included (Item 5).

Report dated November 6, 2003 comprised of exhibits to Registration Statement No. 333-101457 (Item 7).

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[a] Reports filed under File No. 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Dated: November 14, 2003

By: /s/ Donald E. Brandt

Donald E. Brandt
Executive Vice President and Chief
Financial Officer
(Principal Financial Officer
and Officer Duly Authorized
to sign this Report)

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Index to Exhibits

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99.1	Pinnacle West Risk Factors

Exhibit 4.1

PINNACLE WEST CAPITAL CORPORATION

TO

THE BANK OF NEW YORK

TRUSTEE

Second Supplemental Indenture

Dated as of November 1, 2003

To

Indenture

Dated as of December 1, 2000

Floating Rate Senior Notes due 2005

SECOND SUPPLEMENTAL INDENTURE, dated as of November 1, 2003, between Pinnacle West Capital Corporation, a corporation duly organized and existing under the laws of the State of Arizona (herein called the "Company"), having its principal office at 400 North Fifth Street, Phoenix, Arizona 85004, and The Bank of New York, a New York banking corporation, as Trustee (herein called the "Trustee") under the Indenture dated as of December 1, 2000 between the Company and the Trustee (the "Indenture").

RECITALS OF THE COMPANY

The Company has executed and delivered the Indenture to the Trustee to provide for the issuance from time to time of its unsecured debentures, notes or other evidences of indebtedness (the "Securities"), said Securities to be issued in one or more series as in the Indenture provided.

The Company has executed and delivered to the Trustee one indenture supplemental to the Indenture (the "First Supplemental Indenture") dated as of March 15, 2001.

Pursuant to the terms of the Indenture, the Company desires to provide for the establishment of a new series of its Securities to be known as its Floating Rate Senior Notes due 2005 (herein called the "Notes due 2005"), the form and substance of such Notes due 2005 and the terms, provisions, and conditions thereof to be set forth as provided in the Indenture and this Second Supplemental Indenture.

All things necessary to make this Second Supplemental Indenture a valid agreement of the Company, and to make the Notes due 2005, when executed by the Company and authenticated and delivered by the Trustee, the valid and binding obligations of the Company, have been done.

NOW, THEREFORE, THIS SECOND SUPPLEMENTAL INDENTURE WITNESSETH:

For and in consideration of the premises and the purchase of the Notes due 2005 by the holders thereof (the "Holders"), and for the purpose of setting forth, as provided in the Indenture, the form and substance of the Notes due 2005 and the terms, provisions, and conditions thereof, it is mutually agreed, for the equal and proportionate benefit of all Holders of the Notes due 2005, as follows:

ARTICLE ONE

GENERAL TERMS AND CONDITIONS OF THE NOTES DUE 2005

SECTION 101. There shall be and is hereby authorized a series of Securities designated the "Floating Rate Senior Notes due 2005" limited in aggregate principal amount to $165,000,000, except as mentioned below, which amount shall be as set forth in any Company Order for the authentication and delivery of the Notes due 2005. The Notes due 2005 shall mature and the principal shall be due and payable together with all accrued and unpaid interest thereon on November 1, 2005 (the "Maturity Date"), and shall be issued in the form of registered notes without coupons. The Company may, without the consent of the Holders, issue additional Notes due 2005 having the same ranking and the same interest rate, maturity and additional terms as the Notes due 2005. Any additional notes would, together with the Notes due 2005, constitute a single series of Securities under the Indenture. Any reference herein to the limitation in aggregate principal amount of the Notes due 2005 shall take account of any such issuance and the limitation (originally $165,000,000) shall be adjusted accordingly.

SECTION 102. The following defined terms used herein shall, unless the context otherwise requires, have the meanings specified below. Capitalized terms used herein for which no definition is provided herein shall have the meanings set forth in the Indenture.

"Business Day" means any day other than a Saturday or a Sunday or a day on which banking institutions in The City of New York are authorized or required by law or executive order to remain closed or a day on which the Corporate Trust Office of the Trustee is closed for business.

"Calculation Agent" means The Bank of New York or its successor appointed by the Company, acting as calculation agent.

"Interest Determination Date" means the second London Business Day immediately preceding the first day of the relevant Interest Period.

"Interest Period" means the period commencing on an Interest Payment Date (as defined below) for the Notes due 2005 (or commencing on the issue date for the Notes due 2005, if no interest has been paid or duly made available for payment since that date) and ending on the day before the next succeeding Interest Payment Date for the Notes due 2005.

"LIBOR" for any Interest Determination Date will be the London interbank offered rate for deposits in U.S. dollars having an index maturity of three months for a period commencing on the second London Business Day immediately following such Interest Determination Date (the "Three Month Deposits") in amounts of not less than $1,000,000, as such rate appears on Telerate Page 3750, at approximately 11:00 a.m., London time, on such Interest Determination Date.

"London Business Day" means a day on which dealings in deposits in U.S. dollars are transacted, or with respect to any future date, are expected to be transacted, in the London interbank market.

"Telerate Page 3750" means the display designated on page "3750" on Moneyline Telerate (or such other page as may replace the 3750 page on that service or such other service or services as may be nominated by the British Bankers' Association for the purpose of displaying London interbank offered rates for U.S. dollar deposits).

SECTION 103. The Notes due 2005 shall be issued in certificated form, except that the Notes due 2005 shall be issued initially as a Global Security to and registered in the name of Cede & Co., as nominee of The Depository Trust Company, as Depositary therefor. Any Notes due 2005 to be issued or transferred to, or to be held by, Cede & Co. (or any successor thereof) for such purpose shall bear the depositary legend in substantially the form set forth at the top of the

form of Note due 2005 in Article Two hereof (in lieu of that set forth in
Section 204 of the Indenture), unless otherwise agreed by the Company, such agreement to be confirmed in writing to the Trustee. Such Global Security may be exchanged in whole or in part for Notes due 2005 registered, and any transfer of such Global Security in whole or in part may be registered, in the name or names of Persons other than such Depositary or a nominee thereof only under the circumstances set forth in Clause (2) of the last paragraph of Section 305 of the Indenture, or such other circumstances in addition to or in lieu of those set forth in Clause (2) of the last paragraph of Section 305 of the Indenture as to which the Company shall agree, such agreement to be confirmed in writing to the Trustee. Principal of, and premium, if any, and interest on the Notes due 2005 will be payable, the transfer of Notes due 2005 will be registrable and Notes due 2005 will be exchangeable for Notes due 2005 bearing identical terms and provisions, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York; PROVIDED, HOWEVER, that payment of interest may be made at the option of the Company by check mailed to the registered holder at such address as shall appear in the Security Register.

SECTION 104. Each Note due 2005 will bear interest at a per annum rate (the "Rate of Interest") determined by the Calculation Agent (as described below) from November 12, 2003 or from the most recent Interest Payment Date to which interest has been paid or duly provided for until the principal thereof is paid or made available for payment and at the same per annum rate determined by the Calculation Agent on any overdue principal and premium and on any overdue installment of interest, payable on February 1, May 1, August 1 and November 1 of each year (each, an "Interest Payment Date"), commencing on February 1, 2004, to the person in whose name such Note due 2005 or any Predecessor Security is registered, at the close of business on the fifteenth calendar day preceding each Interest Payment Date (each, a "Regular Record Date"). Any such interest installment not punctually paid or duly provided for shall forthwith cease to be payable to the registered Holders on such Regular Record Date, and shall instead be paid to the person in whose name the Note due 2005 (or one or more Predecessor Securities) is registered at the close of business on a Special Record Date to be fixed by the Trustee for the payment of such Defaulted Interest, notice whereof shall be given to the registered Holders of the Notes due 2005 (or one or more Predecessor Securities) not less than ten days prior to such Special Record Date, or may be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange on which the Notes due 2005 may be listed, and upon such notice as may be required by such exchange, all as more fully provided in the Indenture.

The Notes due 2005 will bear interest for each Interest Period at a per annum rate determined by the Calculation Agent. The per annum interest rate will be equal to LIBOR on the relevant Interest Determination Date plus 0.80%; PROVIDED, HOWEVER, that in certain circumstances described below, the interest rate will be determined by the Calculation Agent in an alternative manner without reference to LIBOR. Promptly upon such determination, the Calculation Agent will notify the Trustee of the interest rate for the new Interest Period. The interest rate determined by the Calculation Agent, absent manifest error, shall be binding and conclusive upon the beneficial owners and Holders of the Notes due 2005, the Company and the Trustee.

If the following circumstances exist on any Interest Determination Date, the Calculation Agent shall determine the interest rate for the Notes due 2005 as follows:

(1) In the event LIBOR cannot be determined from the Moneyline Telerate service as described herein as of approximately 11:00 a.m. London time on such Interest Determination Date, the Calculation Agent shall request the principal London offices of each of four major banks in the London interbank market selected by the Calculation Agent (after consultation with the Company) to provide a quotation of the rate (the "Rate Quotation") at which Three Month Deposits in amounts of not less than $1,000,000 are offered by it to prime banks in the London interbank market, at approximately 11:00 a.m. London time on such Interest Determination Date, that is representative of single transactions at such time (the "Representative Amounts"). If at least two Rate Quotations are provided, the interest rate will be the arithmetic mean of the Rate Quotations obtained by the Calculation Agent, plus 0.80%.

(2) In the event LIBOR cannot be determined from the Moneyline Telerate service as described herein and fewer than two Rate Quotations are available as provided in (1) above, the interest rate will be the arithmetic mean of the rates quoted at approximately 11:00 a.m. New York City time on such Interest Determination Date, by three major banks in New York City, selected by the Calculation Agent (after consultation with the Company), for loans in Representative Amounts in U.S. dollars to leading European banks, having an index maturity of three months for a period commencing on the second London Business Day immediately following such Interest Determination Date, plus 0.80% PROVIDED, HOWEVER, that if fewer than three banks selected by the Calculation Agent are quoting such rates, the interest rate for the applicable Interest Period will be the same as the interest rate in effect for the immediately preceding Interest Period.

Upon the request of a Holder of the Notes due 2005, the Calculation Agent will provide to such Holder the interest rate in effect on the date of such request and, if determined, the interest rate for the next Interest Period.

Interest on the Notes due 2005 will be calculated on the basis of the actual number of days for which interest is payable in the relevant Interest Period, divided by 360. All dollar amounts resulting from such calculations will be rounded, if necessary, to the nearest cent with one-half cent rounded upward. In the event that any date on which interest is payable on the Notes due 2005 is not a Business Day, then payment of interest payable on such date will be made on the next succeeding day which is a Business Day (and without any interest or other payment in respect of any such delay), in each case with the same force and effect as if made on such date. If the Maturity Date of the Notes due 2005 or any redemption date falls on a day that is not a Business Day, the payment of principal and interest (to the extent payable with respect to the principal amount being redeemed if on a redemption date) will be made on the next succeeding Business Day, and no interest on such payment shall accrue for the period from and after the maturity date or such redemption date.

SECTION 105. The Company may not redeem the Notes due 2005 prior to November 1, 2004. The Company may redeem the Notes due 2005, in whole, on not less than 30 days' nor more than 60 days' notice, beginning on November 1, 2004 and on each Interest Payment Date thereafter, prior to the Maturity Date of the Notes due 2005, at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest thereon to the date of redemption (the "Redemption Price").

The Company will mail notice of the redemption, first-class mail postage prepaid, to each Holder of Notes due 2005 to be redeemed at the Holder's address in the Securities Register. Notice to the Holders will be given at least 30 but not more than 60 days before the Redemption Date. Notes due 2005 to be redeemed become due on the Redemption Date, and interest will cease to accrue on those Notes due 2005 on the Redemption Date.

The Company agrees that so long as any of the Notes due 2005 remain outstanding, there shall at all times be a calculation agent for the Notes due 2005. If the Calculation Agent is unable or unwilling to continue to act as the Calculation Agent or fails duly to establish the rate of interest for any Interest Period, the Company shall appoint another leading commercial or investment bank engaged in the London interbank market to act as such in its place. In accordance with the agreement between the Company and the Calculation Agent, the Calculation Agent may not resign its duties without a successor calculation agent having been appointed as aforesaid.

SECTION 106. The Notes due 2005 shall be defeasible pursuant to Section 1302 or 1303 of the Indenture.

ARTICLE TWO

FORM OF NOTES DUE 2005

SECTION 201. The Notes due 2005 and the Trustee's certificate of authentication to be endorsed thereon are to be substantially in the following forms:

Form of Face of Security:

UNLESS THIS CERTIFICATE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY, A NEW YORK CORPORATION ("DTC"), TO PINNACLE WEST CAPITAL CORPORATION OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE, OR PAYMENT, AND ANY CERTIFICATE ISSUED IS REGISTERED IN THE NAME OF CEDE & CO. OR IN SUCH OTHER NAME AS IS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC (AND ANY PAYMENT IS MADE TO CEDE & CO. OR TO SUCH OTHER ENTITY AS IS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC), ANY TRANSFER, PLEDGE, OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL INASMUCH AS THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

PINNACLE WEST CAPITAL CORPORATION

Floating Rate Senior Note due 2005

No. _________ $165,000,000
CUSIP No. ______________

Pinnacle West Capital Corporation, a corporation duly organized and existing under the laws of Arizona (herein called the "Company" which term includes any successor person under the Indenture hereinafter referred to), for value received, hereby promises to pay to Cede & Co., as nominee of The Depository Trust Company, or registered assigns, the principal sum of One Hundred Sixty-Five Million Dollars on November 1, 2005 (the "Maturity Date"), and to pay interest at the rate set forth below on the outstanding principal amount hereof from time to time from and including November 12, 2003 or from the most recent Interest Payment Date (as defined below) to which interest has been paid or duly provided for, quarterly in arrears on February 1, May 1, August 1 and November 1 in each year, commencing February 1, 2004, and on the Maturity Date (each, an "Interest Payment Date"), until the principal hereof is paid or made available for payment and at the same per annum rate set forth below on any overdue principal and premium and on any overdue installment of interest. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date shall, as provided herein, be paid to the person in whose name this Note (or one or more predecessor Notes) is registered at the close of business on the fifteenth calendar day preceding each Interest Payment Date, (each a "Regular Record Date"); PROVIDED, HOWEVER, that interest payable on the Maturity Date, or any redemption date, shall be payable to the person to whom the principal amount of this Note is payable. Any interest payable on any Interest Payment Date other than the Maturity Date and not so punctually paid or duly provided for shall forthwith cease to be payable to the person in whose name this Note is registered at the close of business on such Regular Record Date and shall instead be payable to the person in whose name this Note (or one or more predecessor Notes) is registered at the close of business on a special record date for the payment of such interest to be fixed by the Trustee hereinafter referred to, notice whereof shall be given to the registered holder of this Note (or one or more predecessor Notes) not less than ten days prior to such special record date, or may be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange on which this Note may be listed and upon such notice as may be required by such exchange, as more fully provided in the Indenture. Principal of this Note shall be payable against surrender hereof at the corporate trust office of the Trustee or at such other office or agency of the Company as may be designated by it for such purpose in the Borough of Manhattan, The City of New York.

"Business Day" means any day other than a Saturday or a Sunday or a day on which banking institutions in The City of New York are authorized or required by law or executive order to remain closed or a day on which the corporate trust office of the Trustee is closed for business.

"Calculation Agent" means The Bank of New York or its successor appointed by the Company, acting as calculation agent.

"Interest Determination Date" means the second London Business Day immediately preceding the first day of the relevant Interest Period.

"Interest Period" means the period commencing on an Interest Payment Date for this Note (or commencing on the issue date for this Note, if no interest has been paid or duly made available for payment since that date) and ending on the day before the next succeeding Interest Payment Date for this Note.

"LIBOR" for any Interest Determination Date will be the London interbank offered rate for deposits in U.S. dollars having an index maturity of three months for a period commencing on the second London Business Day immediately following such Interest Determination Date (the "Three Month Deposits") in amounts of not less than $1,000,000, as such rate appears on Telerate Page 3750, at approximately 11:00 a.m., London time, on such Interest Determination Date.

"London Business Day" means a day on which dealings in deposits in U.S. dollars are transacted, or with respect to any future date, are expected to be transacted, in the London interbank market.

"Telerate Page 3750" means the display designated on page "3750" on Moneyline Telerate (or such other page as may replace the 3750 page on that service or such other service or services as may be nominated by the British Bankers' Association for the purpose of displaying London interbank offered rates for U.S. dollar deposits).

Payment of the principal of and any interest on this Note will be made at the corporate trust office of the Trustee or at such other office or agency of the Company as may be designated by it for such purpose in the Borough of Manhattan, The City of New York, in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts; PROVIDED, HOWEVER, that, at the option of the Company payment of interest may be made by check mailed to the address of the person entitled thereto as such address shall appear in the register for the Notes.

If any Interest Payment Date falls on a day that is not a Business Day, the Interest Payment Date will be the next succeeding Business Day (without any interest or other payment in respect of such delay). If the maturity date of the Notes or any redemption date falls on a day that is not a Business Day, the payment of principal and interest (to the extent payable with respect to the principal amount being redeemed if on a redemption date) will be made on the next succeeding Business Day, and no interest on such payment shall accrue for the period from and after the maturity date or such redemption date.

Reference is hereby made to the further provisions of this Note set forth on the reverse hereof, which further provisions shall for all purposes have the same effect as if set forth at this place.

Unless the certificate of authentication hereon has been executed by the Trustee referred to on the reverse hereof by manual signature, this Note shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.

IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed under its corporate seal.

PINNACLE WEST CAPITAL CORPORATION

By
Vice President

Attest:

Associate Secretary

Form of Reverse of Security.

This Note is one of a duly authorized issue of securities of the Company (herein called the "Notes"), issued and to be issued in one or more series under an Indenture, dated as of December 1, 2000, as amended and supplemented from time to time (herein called the "Indenture", which term shall have the meaning assigned to it in such instrument), between the Company and The Bank of New York, as Trustee (herein called the "Trustee", which term includes any successor trustee under the Indenture), and reference is hereby made to the Indenture for a statement of the respective rights, limitations of rights, duties and immunities thereunder of the Company, the Trustee and the holders of the Notes and of the terms upon which the Notes are, and are to be, authenticated and delivered. This Note is one of the series designated on the face hereof, limited in aggregate principal amount to $165,000,000, subject to increase as provided in Section 101 of the Second Supplemental Indenture, dated as of November 1, 2003, providing for the Notes.

The Notes are not redeemable prior to November 1, 2004. The Notes will be redeemable at the Company's option in whole, on not less than 30 days' nor more than 60 days' notice, beginning on November 1, 2004 and on each Interest Payment Date thereafter, prior to maturity of the Notes, at a redemption price equal to 100% of the principal amount thereof plus accrued and unpaid interest thereon to the date of redemption.

If notice has been given as provided in the Indenture and funds for the redemption of Notes shall have been made available on the redemption date referred to in such notice, the Notes will cease to bear interest on the date fixed for such redemption specified in such notice and the only right of the holders of the Notes will be to receive payment of the redemption price.

The Company will mail notice of the redemption, first-class mail postage prepaid, to each holder of Notes at the holder's address in the register for the Notes. Notice to the holders will be given at least 30 but not more than 60 days before the redemption date. Notes to be redeemed become due on the redemption date, and interest will cease to accrue on the Notes on the redemption date.

The Notes will not be subject to any sinking fund.

The Notes will bear interest for each Interest Period at a per annum rate determined by the Calculation Agent as described below (the "Rate of Interest"). The per annum interest rate will be equal to LIBOR on the relevant Interest Determination Date plus 0.80%; PROVIDED, HOWEVER, that in certain circumstances described below, the interest rate will be determined by the Calculation Agent in an alternative manner without reference to LIBOR. Promptly upon such determination, the Calculation Agent will notify the Trustee of the interest rate for the new Interest Period. The interest rate determined by the Calculation Agent, absent manifest error, shall be binding and conclusive upon the beneficial owners and holders of the Notes, the Company and the Trustee.

If the following circumstances exist on any Interest Determination Date, the Calculation Agent shall determine the interest rate for the Notes as follows:

(1) In the event LIBOR cannot be determined from the Moneyline Telerate service as described herein as of approximately 11:00 a.m. London time on such Interest Determination Date, the Calculation Agent shall request the principal London offices of each of four major banks in the London interbank market selected by the Calculation Agent (after consultation with the Company) to provide a quotation of the rate (the "Rate Quotation") at which Three Month Deposits in amounts of not less than $1,000,000 are offered by it to prime banks in the London interbank market, at approximately 11:00 a.m. London time on such Interest Determination Date, that is representative of single transactions at such time (the "Representative Amounts"). If at least two Rate Quotations are provided, the interest rate will be the arithmetic mean of the Rate Quotations obtained by the Calculation Agent, plus 0.80%.

(2) In the event LIBOR cannot be determined from the Moneyline Telerate service as described herein and fewer than two Rate Quotations are available as provided in (1) above, the interest rate will be the arithmetic mean of the rates quoted at approximately 11:00 a.m. New York City time on such Interest Determination Date, by three major banks in New York City, selected by the Calculation Agent (after consultation with the Company), for loans in Representative Amounts in U.S. dollars to leading European banks, having an index maturity of three months for a period commencing on the second London Business Day immediately following such Interest Determination Date, plus 0.80% PROVIDED, HOWEVER, that if fewer than three banks selected by the Calculation Agent are quoting such rates, the interest rate for the applicable Interest Period will be the same as the interest rate in effect for the immediately preceding Interest Period.

Upon the request of a holder of the Notes, the Calculation Agent will provide to such holder the interest rate in effect on the date of such request and, if determined, the interest rate for the next Interest Period.

No liability shall (in the absence of gross negligence, willful misconduct or bad faith) attach to the Calculation Agent in connection with the exercise or non-exercise by it of its powers, duties and discretions.

The Indenture contains provisions for defeasance at any time of the entire indebtedness of this Note or certain restrictive covenants and events of default with respect to this Note, in each case upon compliance with certain conditions set forth in the Indenture.

If an event of default with respect to the Notes shall occur and be continuing, the principal of the Notes may be declared due and payable in the manner and with the effect provided in the Indenture.

The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the holders of the Notes to be affected under the Indenture at any time by the Company and the Trustee without the consent of such Holders in certain limited circumstances or with the consent of the Holders of 66 2/3% in principal amount of the securities at the time outstanding of each series to be affected. The Indenture also contains provisions permitting the holders of specified percentages in principal amount of the securities of each series at the time outstanding, on behalf of the holders of all securities of such series, to waive compliance by the Company with certain provisions of the Indenture and certain past defaults under the Indenture and their consequences. Any such consent or waiver by the holder of this Note shall be conclusive and binding upon such holder and upon all future holders of this Note and of any Note issued upon the registration of transfer hereof or in exchange herefor or in lieu hereof, whether or not notation of such consent or waiver is made upon this Note.

As provided in and subject to the provisions of the Indenture, the holder of this Note shall not have the right to institute any proceeding with respect to the Indenture or for the appointment of a receiver or trustee or for any other remedy thereunder, unless such holder shall have previously given the Trustee written notice of a continuing event of default with respect to the Notes, the holders of not less than 25% in principal amount of the Notes at the time outstanding shall have made written request to the Trustee to institute proceedings in respect of such event of default as Trustee and offered the Trustee reasonable indemnity, and the Trustee shall not have received from the holders of a majority in principal amount of Notes at the time outstanding a direction inconsistent with such request, and shall have failed to institute any such proceeding, for 60 days after receipt of such notice, request and offer of indemnity. The foregoing shall not apply to any suit instituted by the holder of this Note for the enforcement of any payment of principal hereof or any premium or interest hereon on or after the respective due dates expressed herein.

No reference herein to the Indenture and no provision of this Note or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of and any premium and interest on this Note at the times, place and rate, and in the coin or currency, herein prescribed.

As provided in the Indenture and subject to certain limitations therein set forth, the transfer of this Note is registrable in the register of the Notes, upon surrender of this Note for registration of transfer at the office or agency of the Company in any place where the principal of and any premium and interest on this Note are payable, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the registrar of the Notes duly executed by the holder hereof or his attorney duly authorized in writing, and thereupon one or more new Notes and of like tenor, of authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees.

The Notes are issuable only in registered form without coupons in denominations of $1,000 and any integral multiple thereof. As provided in the Indenture and subject to certain limitations therein set forth, Notes are exchangeable for a like aggregate principal amount of Notes and of like tenor of a different authorized denomination, as requested by the holder surrendering the same.

No service charge shall be made for any such registration of transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

Prior to due presentment of this Note for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the person in whose name this Note is registered as the owner hereof for all purposes, whether or not this Note be overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

All terms used in this Note which are defined in the Indenture shall have the meanings assigned to them in the Indenture.

This Note shall be governed by and construed in accordance with the law of the State of New York, without regard to conflicts of laws principles thereof.

Form of Trustee's Certificate of Authentication.

CERTIFICATE OF AUTHENTICATION

This is one of the Notes of the series designated therein referred to in the within-mentioned Indenture.

Dated: _____________________ THE BANK OF NEW YORK

AS TRUSTEE

By
AUTHORIZED SIGNATORY

ARTICLE THREE

ORIGINAL ISSUE OF NOTES DUE 2005

SECTION 301. Notes due 2005 in the aggregate principal amount of $165,000,000 (subject to increase as provided in Section 101) may, upon execution of this Second Supplemental Indenture, or from time to time thereafter, be executed by the Company and delivered to the Trustee for authentication, and the Trustee shall thereupon authenticate and deliver said Notes due 2005 in accordance with a Company Order delivered to the Trustee by the Company, without any further action by the Company.

ARTICLE FOUR

PAYING AGENT AND REGISTRAR

SECTION 401. The Bank of New York will be the Paying Agent and Security Registrar for the Notes due 2005.

ARTICLE FIVE

SUNDRY PROVISIONS

SECTION 501. Except as otherwise expressly provided in this Second Supplemental Indenture or in the form of Notes due 2005 or otherwise clearly required by the context hereof or thereof, all terms used herein or in said form of Notes due 2005 that are defined in the Indenture shall have the several meanings respectively assigned to them thereby.

SECTION 502. The Indenture, as heretofore supplemented and amended, and as supplemented by this Second Supplemental Indenture, is in all respects ratified and confirmed, and this Second Supplemental Indenture shall be deemed part of the Indenture in the manner and to the extent herein and therein provided.

SECTION 503. The Trustee hereby accepts the trusts herein declared, provided, created, supplemented, or amended and agrees to perform the same upon the terms and conditions herein and in the Indenture, as heretofore supplemented and amended, set forth and upon the following terms and conditions:

The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Second Supplemental Indenture or for or in respect of the recitals contained herein, all of which recitals are made by the Company solely. In general, each and every term and condition contained in Article Six of the Indenture shall apply to and form a part of this Second Supplemental Indenture with the same force and effect as if the same were herein set forth in full with such omissions, variations, and insertions, if any, as may be appropriate to make the same conform to the provisions of this Second Supplemental Indenture.

This instrument may be executed in any number of counterparts, each of which so executed shall be deemed to be an original, but all such counterparts shall together constitute but one and the same instrument.

IN WITNESS WHEREOF, the parties hereto have caused this Second Supplemental Indenture to be duly executed, and their respective corporate seals to be hereunto affixed and attested, all as of the day and year first above written.

PINNACLE WEST CAPITAL CORPORATION

Attest:

/s/ Betsy A. Pregulman

Betsy A. Pregulman
Associate Secretary

By: /s/ Barbara M. Gomez

Barbara M. Gomez
Treasurer

THE BANK OF NEW YORK, as Trustee

Attest:

/s/ Barbara Bevelaqua

Barbara Bevelaqua
Vice President

By: /s/ Van K. Brown

Van K. Brown
Vice President

STATE OF ARIZONA)
) ss.:
COUNTY OF MARICOPA)

On the 10th day of November, 2003, before me personally came Barbara M. Gomez, to me known, who, being by me duly sworn, did depose and say that she is the Treasurer of Pinnacle West Capital Corporation, one of the corporations described in and which executed the foregoing instrument; that she knows the seal of said corporation; that the seal affixed to said instrument is such corporate seal; that it was so affixed by authority of the Board of Directors of said corporation; and that she signed her name thereto by like authority.

/s/ Linda K. Redman

Notary Public

My Commission Expires:

February 8, 2007

STATE OF NEW YORK)
) ss.:
COUNTY OF NEW YORK)

On the 10th day of November, 2003, before me personally came Van K. Brown, to me known, who, being by me duly sworn, did depose and say that he is a Vice President of The Bank of New York, one of the corporations described in and which executed the foregoing instrument; that he knows the seal of said corporation; that the seal affixed to said instrument is such corporate seal; that it was so affixed by authority of the Board of Directors of said corporation; and that he signed his name thereto by like authority.

/s/ Robert Hirsch

Notary Public

My Commission Expires:

July 1, 2006

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EXHIBIT 12.1

PINNACLE WEST CAPITAL CORPORATION
COMPUTATION OF EARNINGS TO FIXED CHARGES
(THOUSANDS OF DOLLARS)

	Nine Months Ended September 30, 2003	Twelve Months Ended December 31, 2002	2001	2000	1999	1998
Earnings:						
Income from Continuing Operations	$184,580	$206,198	$327,367	$302,332	$269,772	$242,892
Income Taxes	98,530	132,228	213,535	194,200	141,592	138,589
Fixed Charges	174,982	219,651	211,958	202,804	194,070	201,184
Total	458,092	558,077	752,860	699,336	605,434	582,665
Fixed Charges:						
Interest Expense	151,539	187,512	175,822	166,447	157,142	163,975
Estimated Interest Portion of Annual Rents	23,443	32,139	36,136	36,357	36,928	37,209
Total Fixed Charges	174,982	219,651	211,958	202,804	194,070	201,184
Ratio of Earnings to Fixed Charges (rounded down)	2.61	2.54	3.55	3.44	3.11	2.89

Exhibit 31.1

CERTIFICATION

I, William J. Post, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pinnacle West Capital Corporation;

2. Based on my knowledge, this 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 report is being prepared;

   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 14, 2003

/s/ William J. Post

William J. Post
Chief Executive Officer and
Chairman of the Board

Exhibit 31.2

CERTIFICATION

I, Donald E. Brandt, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pinnacle West Capital Corporation;

2. Based on my knowledge, this 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 report is being prepared;

   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 14, 2003

/s/ Donald E. Brandt

Donald E. Brandt
Executive Vice President and
Chief Financial Officer

Exhibit 32.1

Form of Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(William J. Post)

I, William J. Post, the Chairman of the Board and Chief Executive Officer of Pinnacle West Capital Corporation ("Pinnacle West"), certify, to the best of my knowledge, that: (a) the attached Quarterly Report on Form 10-Q of Pinnacle West for the fiscal quarter ended September 30, 2003 (the "September 2003 Form 10-Q") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (b) the information contained in the September 2003 Form 10-Q Report fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West.

/s/ William J. Post

William J. Post
Chairman of the Board and
Chief Executive Officer

Date: November 14, 2003

Exhibit 32.2

Form of Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(Donald E. Brandt)

I, Donald E. Brandt, Executive Vice President and Chief Financial Officer, of Pinnacle West Capital Corporation ("Pinnacle West"), certify, to the best of my knowledge, that: (a) the attached Quarterly Report on Form 10-Q of Pinnacle West for the quarter ended September 30, 2003 (the "September 2003 Form 10-Q") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (b) the information contained in the September 2003 Form 10-Q Report fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West.

/s/ Donald E. Brandt

Donald E. Brandt
Executive Vice President and
Chief Financial Officer

Date: November 14, 2003

Exhibit 99.1

PINNACLE WEST RISK FACTORS

Set forth below and in other documents we file with the Securities and Exchange Commission are risks and uncertainties that could affect our financial results.

Our cash flow largely depends on the performance of our subsidiaries.

We conduct our operations primarily through subsidiaries. Substantially all of our consolidated assets are held by such subsidiaries. Accordingly, our cash flow is dependent upon the earnings and cash flows of these subsidiaries and their distributions to us. The subsidiaries are separate and distinct legal entities and have no obligation to make distributions to us.

The debt agreements of some of our subsidiaries may restrict their ability to pay dividends, make distributions or otherwise transfer funds to us. As part of the approval by the Arizona Corporation Commission ("ACC") of a $500 million financing arrangement between Arizona Public Service Company ("APS") and Pinnacle West Energy Corporation ("Pinnacle West Energy"), APS must maintain a common equity ratio of at least 40% and may not pay common dividends if the payment would reduce its common equity below that threshold. As defined in the ACC financing order approving the arrangement, common equity ratio is common equity divided by common equity plus long-term debt, including current maturities of long-term debt. At September 30, 2003, APS' common equity ratio was approximately 46%..

We are subject to complex government regulation which may have a negative impact on our business and our results of operations.

We are, directly and through our subsidiaries, subject to governmental regulation which may have a negative impact on our business and results of operations. We are a "holding company" within the meaning of the Public Utility Holding Company Act ("PUHCA"); however, we are exempt from the provisions of PUHCA by virtue of our filing of an annual exemption statement with the SEC.

APS is subject to comprehensive regulation by several federal, state and local regulatory agencies, which significantly influence its operating environment and may affect its ability to recover costs from utility customers. APS is required to have numerous permits, approvals and certificates from the agencies that regulate APS' business. The Federal Energy Regulatory Commission ("FERC"), the Nuclear Regulatory Commission ("NRC"), the Environmental Protection Agency ("EPA"), and the ACC regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that APS can charge customers. We believe the necessary permits, approvals and certificates have been obtained for APS' existing operations. However, we are unable to predict the impact on our business and operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

We cannot predict the outcome of APS' general rate case pending before the ACC.

As required by a 1999 settlement agreement among APS and various parties (the "1999 Settlement Agreement"), on June 27, 2003, APS filed a general rate case with the ACC. APS requested a $175.1 million, or 9.8%, increase in its annual retail electricity revenues, to become effective July 1, 2004. The major reasons for the request include:

- complying with the provisions of the 1999 Settlement Agreement;
- incorporating significant increases in fuel and purchased power costs, including results of purchases through the ACC's "Track B" procurement process;
- recognizing changes in APS' cost of service, cost allocation and rate design;

- obtaining rate base recognition of the generating plants built in Arizona by Pinnacle West Energy since 1999 to serve APS' retail electricity customers (specifically, Redhawk Units 1and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3);

- recovering $234 million written off by APS as a result of the 1999 Settlement Agreement; and

- recovering restructuring and compliance costs associated with the ACC's electric competition rules.

The general rate case will also address the implementation of rate adjustment mechanisms that were the subject of ACC hearings in April 2003. The rate adjustment mechanisms, which were authorized in the 1999 Settlement Agreement, would allow APS to recover several types of costs, the most significant of which are power supply costs (fuel and purchased power costs) and costs associated with complying with the ACC retail competition rules described below. If APS does not have a rate adjustment mechanism that allows it to recover its full costs of procuring fuel for its generating plants, then changes in fuel prices may increase its cost of producing power or decrease the amount it receives from selling power, harming our financial performance. On November 4, 2003, the ACC approved the issuance of an order which authorizes a rate adjustment mechanism allowing APS to recover changes in purchased power costs (but not changes in fuel costs) incurred after July 1, 2004. The other rate adjustment mechanisms authorized in the 1999 Settlement Agreement (such as the costs associated with complying with the ACC electric competition rules) were also tentatively approved for subsequent implementation in the general rate case. The purchased power rate adjustment mechanism will not become effective until there is a final order in the general rate case, and the ACC further reserved the right to amend or modify, in all respects, this November 4 order during the rate case. We assume that the ACC will make a decision in the general rate case by the end of 2004. We cannot predict the outcome of the rate case and the resulting levels of regulated revenues.

The procurement of wholesale power by APS without the ability to adjust retail rates could have an adverse impact on our business and financial results.

The 1999 Settlement Agreement limits APS' ability to change retail rates until at least July 1, 2004, which could have a significant adverse financial impact on us if wholesale power prices significantly exceed the amount included for generation costs in APS' current bundled retail rates. Under the ACC's rules, APS is the "provider of last resort" for standard-offer, full-service customers under rates that have been approved by the ACC. The 1999 Settlement Agreement allows APS 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 APS' 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 APS' current retail rates. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain an adjustment of its rates under the emergency provisions of the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power. In addition, APS filed a general rate case with the ACC on June 27, 2003 (see discussion above). Among other things, the rate case will address the implementation of rate adjustment mechanisms, which would allow APS to recover several types of costs, the most significant of which are power supply costs (fuel and purchased power costs) and costs associated with complying with the ACC retail competition rules.

If we are not able to access capital at competitive rates, our ability to implement our financial strategy will be adversely affected.

We rely on access to both short-term money markets and longer-term capital markets as a significant source of liquidity and for capital requirements not satisfied by the cash flow from our operations. We believe that we will maintain sufficient access to these financial markets based upon current credit ratings. However, certain market disruptions or a downgrade of our credit rating may increase our cost of borrowing or adversely affect our ability to access one or more financial markets. Such disruptions could include:

- an economic downturn;

- capital market conditions generally;
- the bankruptcy of an unrelated energy company;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on our facilities or those of unrelated energy companies; or
- the overall health of the utility industry.

Changes in economic conditions could result in higher interest rates, which would increase our interest expense on our debt and reduce funds available to us for our current plans. Additionally, an increase in our leverage could adversely affect us by:

- increasing the cost of future debt financing;
- increasing our vulnerability to adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes; and
- placing us at a competitive disadvantage compared to our competitors that have less debt.

A significant reduction in our credit ratings could materially and adversely affect our business, financial condition and results of operations.

We cannot be sure that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade could increase our borrowing costs which would diminish our financial results. We would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease. In addition, borrowing costs under certain of our existing credit facilities depend on our credit ratings. A downgrade could also require us to provide additional support in the form of letters of credit or cash or other collateral to various counterparties. If our short-term ratings were to be lowered, it could limit our access to the commercial paper market. We note that the ratings from credit agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating.

Deregulation or restructuring of the electric industry may result in increased competition, which could have a significant adverse impact on our business and our financial results.

Retail competition could have a significant adverse financial impact on us due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. In 1999, the ACC approved rules that provide a framework for the introduction of retail electric competition in Arizona. Under the rules, as modified by the 1999 Settlement Agreement, APS was required to transfer all of its 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. To satisfy this requirement APS had planned to transfer its generation assets to Pinnacle West Energy. Pursuant to an ACC order dated September 10, 2002, the ACC unilaterally modified the 1999 Settlement Agreement and directed APS to cancel any plans to divest interests in any of its generating assets. The ACC further established a requirement that APS solicit bids for certain estimated amounts of capacity and energy for periods beginning July 1, 2003. Pinnacle West Energy bid on and entered into contracts to supply most of APS' requirements in the summer months through September 2006. These regulatory developments and legal challenges to the rules have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

As a result of changes in federal law and regulatory policy, competition in the wholesale electricity market has greatly increased due to a greater participation by traditional electricity suppliers, non-utility generators, independent power producers, and wholesale power marketers and brokers. This increased competition could affect our load forecasts, plans for power supply and wholesale energy sales and related revenues. As a result of the changing regulatory environment and the relatively low barriers to entry, we expect wholesale competition to increase. As competition continues to increase, our financial position and results of operations could be adversely affected.

Recent events in the energy markets that are beyond our control may have negative impacts on our business.

As a result of the energy crisis in California during the summer of 2001, the recent volatility of natural gas prices in North America, the filing of bankruptcy by the Enron Corporation, and investigations by governmental authorities into energy trading activities, companies generally in the regulated and unregulated utility businesses have been under an increased amount of public and regulatory scrutiny. The capital markets and ratings agencies also have increased their level of scrutiny. We believe that we are complying with all applicable laws, but it is difficult or impossible to predict or control what effect these or related issues may have on our business or our access to the capital markets.

Our results of operations can be adversely affected by milder weather.

Weather conditions directly influence the demand for electricity and affect the price of energy commodities. Electric power demand is generally a seasonal business. In Arizona, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, our overall operating results fluctuate substantially on a seasonal basis. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. As a result, unusually mild weather could diminish our results of operations and harm our financial condition.

There are inherent risks in the operation of nuclear facilities, such as environmental, health and financial risks and the risk of terrorist attack.

Through APS, we have an ownership interest in and operate the Palo Verde Nuclear Generating Station (“Palo Verde”), which is the largest nuclear electric generating facility in the United States. Palo Verde is subject to environmental, health and financial risks such as the ability to dispose of spent nuclear fuel, the ability to maintain adequate reserves for decommissioning, potential liabilities arising out of the operation of these facilities, and the costs of securing the facilities against possible terrorist attacks. We maintain nuclear decommissioning trust funds and external insurance coverage to minimize our financial exposure to these risks; however, it is possible that damages could exceed the amount of insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of noncompliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. In addition, although we have no reason to anticipate a serious nuclear incident at Palo Verde, if an incident did occur, it could materially and adversely affect our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

The operation of Palo Verde requires licenses that need to be periodically renewed and/or extended. We do not anticipate any problems renewing these licenses. However, as a result of potential terrorist threats and increased public scrutiny of utilities, the licensing process could result in increased licensing or compliance costs that are difficult or impossible to predict.

The use of derivative contracts in the normal course of our business and changing interest rates and market conditions could result in financial losses that negatively impact our results of operations.

Our operations include managing market risks related to commodity prices. We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances and credits. We have established procedures to 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 commodity.

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 all counterparties. Despite the fact that the 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 adverse impact on our earnings for a given period.

Changing interest rates will affect interest paid on variable-rate debt and interest earned by our pension plan and nuclear decommissioning trust funds. Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The pension plan is also impacted by the discount rate, which is the interest rate used to discount future pension obligations. Continuation of recent decreases in the discount rate would result in increases in pension costs, cash contributions, and charges to other comprehensive income. The pension plan and nuclear decommissioning trust funds also have risks associated with changing market values of equity investments. A significant portion of the pension costs and all of the nuclear decommissioning costs are recovered in regulated electricity prices.

The uncertain outcome regarding the creation of regional transmission organizations, or RTOs, and implementation of the FERC's standard market design, or SMD, may materially impact our operations, cash flows or financial position.

In a December 1999 order, the FERC set minimum characteristics and functions that must be met by utilities that participate in regional transmission organizations. 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. Additionally, the FERC is considering implementing a standard market design for wholesale markets. On October 16, 2001, APS 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. 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. On September 15, 2003, the FERC issued an order granting clarification and rehearing, in part, of its prior orders. In particular, this order approved the use of a physical congestion management scheme for WestConnect for an initial phase-in period. FERC indicated that the WestConnect utilities and the appropriate regional state advisory committee should develop a market based congestion management scheme for subsequent implementation. APS is now participating in a cost/benefit analysis of implementing WestConnect, and the results of this analysis are expected to be completed in the first quarter of 2004.

We are subject to numerous environmental laws and regulations which may increase our cost of operations, impact our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste, and hazardous waste. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. We cannot predict the outcome (financial or operational) of any related litigation that may arise.

In addition, we may be a responsible party for environmental clean up at sites identified by a regulatory body. We cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean-up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties.

We cannot be sure that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from APS' customers, could have a material adverse effect on our results of operations.

Actual results could differ from estimates used to prepare our financial statements.

In preparing the financial statements in accordance with generally accepted accounting principles, 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.