PINNACLE WEST CAPITAL CORP

FORM 10-Q
(Quarterly Report)

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Industry	Electric Utilities
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Fiscal Year	12/31

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FORM 10-Q

Securities and Exchange Commission
Washington, D.C. 20549

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2004

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 [X] No [ ]

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

Yes [X] 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 May 5, 2004: 91,359,180

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Glossary

ACC – Arizona Corporation Commission

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

CC&N – Certificate of Convenience and Necessity

Citizens – Citizens Communications Company

Company – Pinnacle West Capital Corporation

CPUC – California Public Utility Commission

DIG – Derivative Implementation Group

DOE – United States Department of Energy

EITF – the FASB's Emerging Issues Task Force

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

EPA – United States Environmental Protection Agency

ERMC – Energy Risk Management Committee

FASB – Financial Accounting Standards Board

FERC – United States Federal Energy Regulatory Commission

FIN – FASB Interpretation

Financing Order – ACC order that authorized APS' $500 million loan to Pinnacle West Energy in May 2003

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

IRS – United States Internal Revenue Service

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

NRC – United States Nuclear Regulatory Commission

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

OCI – other comprehensive income

Palo Verde – Palo Verde Nuclear Generating Station

PG&E – PG&E Corp.

Pinnacle West – Pinnacle West Capital Corporation, 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

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

Superfund – Comprehensive Environmental Response, Compensation and Liability Act

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

2003 Form 10-K – the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2003

VIE – variable interest entity

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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 March 31, 2004	Three Months Ended March 31, 2003
Operating Revenues		
Regulated electricity segment	$415,464	$379,678
Marketing and trading segment	88,383	116,706
Real estate segment	51,593	40,688
Other revenues	18,929	15,571
Total	574,369	552,643
Operating Expenses		
Regulated electricity segment purchased power and fuel	88,611	69,389
Marketing and trading segment purchased power and fuel	67,764	97,608
Operations and maintenance	138,656	133,117
Real estate segment operations	47,690	40,159
Depreciation and amortization	101,504	105,398
Taxes other than income taxes	30,330	28,496
Other expenses	16,443	9,221
Total	490,998	483,388
Operating Income	83,371	69,255
Other		
Allowance for equity funds used during construction	2,002	—
Other income (Note 16)	11,412	5,721
Other expense (Note 16)	(5,945)	(4,197)
Total	7,469	1,524
Interest Expense		
Interest charges	50,356	47,851
Capitalized interest	(4,911)	(9,979)
Total	45,445	37,872
Income From Continuing Operations Before Income Taxes	45,395	32,907
Income Taxes	15,627	12,754
Income From Continuing Operations	29,768	20,153
Income From Discontinued Operations - Net of Income Tax Expense of $252 and $3,375	388	5,145
Net Income	$ 30,156	$ 25,298
Weighted-Average Common Shares Outstanding - Basic	91,294	91,256
Weighted-Average Common Shares Outstanding - Diluted	91,376	91,359
Earnings Per Weighted-Average Common Share Outstanding (Note 18)		
Income From Continuing Operations - Basic	$ 0.33	$ 0.22
Net Income - Basic	0.33	0.28
Income From Continuing Operations - Diluted	0.33	0.22
Net Income - Diluted	0.33	0.28
Dividends Declared Per Share	$ 0.450	$ 0.425

See Notes to Condensed Consolidated Financial Statements.

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

	March 31, 2004	December 31, 2003
Current Assets		
Cash and cash equivalents	$ 19,194	$ 228,779
Customer and other receivables	288,810	365,732
Allowance for doubtful accounts	(4,738)	(9,223)
Accrued utility revenues	89,347	88,629
Materials and supplies (at average cost)	96,413	96,099
Fossil fuel (at average cost)	24,385	28,367
Assets from risk management and trading activities (Note 10)	151,521	97,630
Other current assets	73,432	73,034
Total current assets	738,364	969,047
Investments and Other Assets		
Real estate investments—net	345,843	343,322
Assets from risk management and trading activities - long-term (Note 10)	175,191	138,946
Decommissioning trust accounts	246,002	240,645
Other assets	95,810	88,816
Total investments and other assets	862,846	811,729
Property, Plant and Equipment		
Plant in service and held for future use	9,969,094	9,925,344
Less accumulated depreciation and amortization	3,195,467	3,160,675
Total	6,773,627	6,764,669
Construction work in progress	540,361	554,876
Intangible assets, net of accumulated amortization	125,029	108,534
Nuclear fuel, net of accumulated amortization	57,959	52,011
Net property, plant and equipment	7,496,976	7,480,090
Deferred Debits		
Regulatory assets	161,543	164,804
Other deferred debits	115,663	110,708
Total deferred debits	277,206	275,512
Total Assets	$9,375,392	$9,536,378

See Notes to Condensed Consolidated Financial Statements.

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

	March 31, 2004	December 31, 2003
Current Liabilities		
Accounts payable	$ 237,522	$ 293,427
Accrued taxes	103,660	69,769
Accrued interest	47,077	51,825
Short-term borrowings	235,086	86,081
Current maturities of long-term debt	441,079	705,820
Customer deposits	50,473	49,783
Deferred income taxes	631	631
Liabilities from risk management and trading activities (Note 10)	108,601	92,755
Other current liabilities	101,632	81,223
Total current liabilities	1,325,761	1,431,314
Long-Term Debt Less Current Maturities	2,462,838	2,617,385
Deferred Credits and Other		
Deferred income taxes	1,356,929	1,329,253
Regulatory liabilities	512,190	510,423
Pension liability	202,745	188,041
Liability for asset retirement (Note 13)	238,566	234,440
Liabilities from risk management and trading activities - long-term (Note 10)	111,998	82,730
Unamortized gain - sale of utility plant	53,765	54,909
Other	260,204	258,104
Total deferred credits and other	2,736,397	2,657,900
Commitments and Contingencies (Notes 5, 12 and 13)		
Common Stock Equity		
Common stock, no par value	1,746,189	1,744,354
Treasury stock	(2,356)	(3,273)
Total common stock	1,743,833	1,741,081
Accumulated other comprehensive income (loss):		
Minimum pension liability adjustment	(66,564)	(66,564)
Derivative instruments	56,351	27,563
Total accumulated other comprehensive loss	(10,213)	(39,001)
Retained earnings	1,116,776	1,127,699
Total common stock equity	2,850,396	2,829,779
Total Liabilities and Equity	$9,375,392	$9,536,378

See Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31, 2004	Three Months Ended March 31, 2003
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 30,156	$ 25,298
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale of discontinued operations	(388)	(5,145)
Depreciation and amortization	101,504	105,398
Nuclear fuel amortization	7,599	7,726
Allowance for equity funds used during construction	(2,002)	—
Deferred income taxes	9,060	(9,675)
Change in mark-to-market	(22,920)	(6,008)
Changes in current assets and liabilities:		
Customer and other receivables	72,437	33,040
Accrued utility revenues	(718)	15,609
Materials, supplies and fossil fuel	3,668	(4,191)
Other current assets	(398)	16,234
Accounts payable	(52,008)	(55,049)
Accrued taxes	33,891	36,909
Accrued interest	(4,748)	(10,255)
Other current liabilities	21,099	17,482
Proceeds from the sale of real estate assets	8,607	10,824
Change in real estate investments	(11,573)	(15,101)
Increase in regulatory assets	(847)	(2,152)
Change in risk management and trading - assets	5,875	11,334
Change in risk management and trading - liabilities	19,427	(12,370)
Change in customer advances	3,070	(1,334)
Change in pension liability	14,704	15,576
Change in other long-term assets	(10,189)	6,278
Change in other long-term liabilities	1,075	1,006
Net cash flow provided by operating activities	226,381	181,434
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(115,183)	(174,324)
Capitalized interest	(4,911)	(9,979)
Trust fund for bond redemption	—	(87,225)
Proceeds from sale of assets from discontinued operations	133	25,150
Other	(4,194)	8,238
Net cash flow used for investing activities	(124,155)	(238,140)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	179,000	18,500
Short-term borrowings and payments—net	149,005	105,484
Dividends paid on common stock	(41,080)	(38,783)
Repayment of long-term debt	(601,488)	(40,325)
Other	2,752	1,553
Net cash flow (used for) provided by financing activities	(311,811)	46,429
Net Decrease in Cash and Cash Equivalents	(209,585)	(10,277)
Cash and Cash Equivalents at Beginning of Period	228,779	77,566
Cash and Cash Equivalents at End of Period	$ 19,194	$ 67,289
Supplemental disclosure of cash flow information:		
Cash paid during the period for:		
Interest paid, net of amounts capitalized	$ 72,367	$ 46,439

Income taxes paid	$	6,767	$	—

See Notes to Condensed Consolidated Financial Statements.

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. Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. We have reclassified certain prior year amounts to conform to the current year presentation (see Note 10).

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. 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 2003 Form 10-K.

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. On February 2, 2004, we used proceeds from the $165 million Floating Rate Notes issued on November 12, 2003 and short term borrowings to pay down the maturing $215 million 4.5% Senior Notes due 2004.

On February 15, 2004, $125 million of APS' 5.875% Notes due 2004, were redeemed at maturity and on March 1, 2004, $80 million of APS First Mortgage Bonds, 6.625% Series due 2004, were redeemed at maturity. APS used cash from operations and short-term debt to redeem the maturing debt.

On March 31, 2004, the Navajo County, Arizona Pollution Control Corporation issued $166 million of variable interest rate pollution control bonds, 2004 Series A-E, due 2034. The bonds were issued to refinance $166 million of outstanding pollution control bonds. These bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and the Navajo County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Condensed Consolidated Balance Sheets.

Also on March 31, 2004, Coconino County, Arizona Pollution Control Corporation issued $13 million of variable interest rate pollution control bonds, 2004 Series A, due 2034. The bonds were issued to refinance $13 million of outstanding pollution control bonds. These bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Coconino County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Condensed Consolidated Balance Sheets.

At March 31, 2004, APS had $387 million of pollution control bonds under which interest rates are reset on a daily or annual basis. The holders of these bonds have the right to cause APS to purchase their bonds on the applicable reset date if the bonds are not remarketed; therefore, $337 million of such bonds are classified as current maturities of long-term debt. The remaining $50 million is classified as long-term as APS has the intent and ability, demonstrated by credit agreements in place that extend for more than one year, to refinance any bonds that APS is required to purchase.

The following is a list of payments due on total long-term debt and capitalized lease requirements as of March 31, 2004:

- $341 million in 2004;
- $569 million in 2005;
- $395 million in 2006;
- $2 million in 2007;
- $8 million in 2008; and
- $1,597 million thereafter.

5. Regulatory Matters

Electric Industry Restructuring

State

Overview

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) ($234 million pre-tax) 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 discussed 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 discussed 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 appealed the ruling to the Arizona Court of Appeals, and in January 2004, the Court invalidated some, but not all, of the Rules as either violative of Arizona's constitutional requirement that the ACC consider the "fair value" of a utility's property in setting rates or as being beyond the ACC's constitutional and statutory powers. Other Rules were set aside for failure to submit such regulations to the Arizona Attorney General for approval as required by statute.

Provider of Last Resort Obligation

Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is, under the Rules, 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. 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. 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. 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 are limited to the issues described in the preceding bullet points.

On August 27, 2003, APS, Pinnacle West and Pinnacle West Energy filed a lawsuit 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 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 Order

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. The ACC has indicated that the preliminary investigation would be addressed in the pending general rate case (see 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.

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, intended 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 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.

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 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.

Testimony On February 3, 2004, the following parties filed their initial written testimony with the ACC on all issues except cost of service (i.e., cost allocation among customer classes) and rate design:

- the ACC "litigation" staff;

- the Arizona Residential Utility Consumers Office ("RUCO"), an office established by the Arizona legislature to represent the interests of residential utility consumers before the ACC; and

- other approved rate case interveners.

ACC Staff Recommendations In its filed testimony, the ACC staff recommended, among other things, that the ACC:

- decrease APS' annual retail electricity revenues by at least $142.7 million, which would result in a rate decrease of approximately 8%, based on a 9% return on equity;

- not allow the PWEC Dedicated Assets to be included in APS' rate base;

- not allow APS to recover any of the $234 million pretax written off as a result of the 1999 Settlement Agreement; and

- not implement any adjustment mechanisms for fuel and purchased power.

The ACC staff recommendations, if implemented as proposed, could have a material adverse impact on our results of operations, financial position, liquidity, dividend sustainability, credit ratings and access to capital markets. We believe that APS' rate case requests are supported by, among other things, APS' demonstrated need for the PWEC Dedicated Assets; APS' need to attract capital at reasonable rates of return to support the required capital investment to ensure continued customer reliability in APS' high-growth service territory; and the conditions in the western energy market. As a result, we believe it is unlikely that the ACC would adopt the ACC staff recommendations in their present form, although we can give no assurances in that regard.

The ACC staff also submitted testimony indicating that APS and its affiliates had violated the "spirit, if not the letter" of the Rules, the Code of Conduct and the 1999 Settlement Agreement.

RUCO Recommendations In its filed testimony, RUCO recommended, among other things, that the ACC:

- decrease APS' annual retail electricity revenues by $53.6 million, which would result in a rate decrease of approximately 2.84%, based on a 9.5% return on equity;

- not allow the PWEC Dedicated Assets to be included in APS' rate base;

- not allow APS to recover any of the $234 million pretax written off as a result of the 1999 Settlement Agreement; and

- not implement any adjustment mechanisms for fuel and purchased power.

APS believes that its rate request is necessary to ensure APS' continued ability to reliably serve one of the fastest growing regions in the country and views any ultimate decision that would deny recovery of the Company's investment in the PWEC Dedicated Assets as constituting a regulatory "taking." APS will vigorously oppose the recommendations of the ACC staff, RUCO, and other parties offering similar recommendations.

Estimated Timeline APS has asked the ACC to approve the requested rate increase by July 1, 2004. Hearings on the rate case were previously scheduled to begin on May 25, 2004. On April 15, 2004, the ACC ALJ issued a procedural order revising the schedule and timing of the rate case. On April 29, 2004, the ACC ALJ issued an order staying the existing procedural schedule for 30 days while the parties discuss settlement. The ALJ scheduled a procedural conference on May 26, 2004, to determine whether the stay should be extended or a new procedural schedule and hearing date established. Based on these two recent procedural orders, hearings should begin no earlier than early August 2004.

Request for Proposals

In early December 2003, APS issued a request for proposals ("RFP") for long-term power supply resources, and on January 8, 2004, an ACC ALJ issued an order requiring, among other things, APS to file a summary of the proposals with the ACC. On January 27, 2004, APS filed a summary of the proposals with the ACC. APS is negotiating with certain of the parties that submitted proposals.

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. 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. Retirement Plans and Other Benefits

Pinnacle West sponsors a qualified defined benefit pension plan, a non-qualified supplemental excess benefit retirement plan, and other postretirement benefits for the employees of Pinnacle West and our subsidiaries.

On December 8, 2003, the President signed the "Medicare Prescription Drug, Improvement and Modernization Act of 2003" (the Act). One feature of the Act is a government subsidy of prescription drug costs. We have not yet quantified the effect, if any, on accumulated projected benefit obligations or the net periodic postretirement benefit cost in our financial statements and accompanying notes. Specific accounting guidance for this subsidy, including transition rules, is pending.

The following table provides details of the plans' benefit costs for the three months ended March 31, 2004 and 2003. Also included is the portion of these costs charged to expense, including administrative costs and excluding amounts billed to electric plant participants or amounts capitalized as overhead construction (dollars in thousands):

	Pension Benefits		Other Benefits	
	2004	2003	2004	2003
Service cost-benefits earned during the period	$ 10,603	$ 8,664	$ 4,779	$ 3,780
Interest cost on benefit obligation	20,927	17,701	7,825	7,191
Expected return on plan assets	(20,376)	(14,962)	(5,622)	(4,473)
Amortization of:				
Transition (asset)/obligation	(804)	(743)	703	716
Prior service cost/(credit)	629	552	(23)	(29)
Net actuarial loss	4,246	4,171	2,764	2,315
Net periodic benefit cost	$ 15,225	$ 15,383	$10,426	$ 9,500
Portion of cost charged to expense	$ 6,851	$ 6,922	$ 4,691	4,275

Contributions

The Pension Stability Act was signed into law on April 10, 2004. Under this new legislation, our required pension contribution in 2004 is $35 million. We are currently evaluating whether any additional contributions will be made to our pension plans in 2004. We have not yet made any 2004 contributions to our pension plans or other postretirement benefit plans.

7. Business Segments

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

- our regulated electricity segment, which consists of traditional regulated 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 amounts in our other segment include activities principally related to El Dorado's investment in NAC, as well as the parent company and APS Energy Services' non-commodity activities. Financial data for the Company's business segments follows (dollars in millions):

	Three Months Ended March 31,	
	2004	2003
Operating Revenues:		
Regulated electricity	$415	$380
Marketing and trading	88	117
Real estate	52	41
Other	19	15
Total	$574	$553
Net Income:		
Regulated electricity	$ 17	$ 9
Marketing and trading	10	7
Real estate [(a)]	2	6
Other	1	3
Total	$ 30	$ 25

(a) Real estate net income includes income from discontinued operations (net of income taxes) in the following amounts: $0.4 million for the three months ended March 31, 2004 and $5 million for the three months ended March 31, 2003. See Note 19 for further discussion of our real estate activities.

	As of March 31, 2004	As of December 31, 2003
Assets:		
Regulated electricity	$8,213	$8,405
Marketing and trading	739	680
Real estate	398	424
Other	25	27
Total	$9,375	$9,536

8. Accounting Matters

See the following Notes for information about new accounting standards and other accounting matters:

- Note 9 for FASB interpretation (FIN No. 46R) related to variable interest entities;
- Note 10 for EITF issue (EITF 03-11) and DIG Issue No. C15 related to accounting for derivatives and energy trading contracts; and
- Note 13 for accounting standard (SFAS No. 143) on asset retirement obligations.

9. Variable Interest Entities

In 2003, we adopted FIN No. 46R, "Consolidation of Variable Interest Entities," as it applies to special-purpose entities. FIN No. 46R 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.

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. Based on our assessment of FIN No. 46R, we are not required to consolidate the Palo Verde VIEs.

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 March 31, 2004, APS would have been required to assume approximately $268 million of debt and pay the equity participants approximately $200 million.

In the first quarter of 2004, we adopted FIN No. 46R for all other contractual arrangements. There was no impact to our financial statements.

10. Derivative Instruments and Energy Trading Activities

We are exposed to the impact of market fluctuations in interest rates and 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 instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge our exposure to changes in interest rates and 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 transactions. 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 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 Issue No. 02-3,” effective October 1, 2003. EITF 03-11 provides guidance on whether realized gains and losses on physically settled derivative contracts that are not held for trading purposes should be reported on a net or gross basis. The EITF concludes that such classification is a matter of judgment that depends on the relevant facts and circumstances. In the electricity business, some contracts to purchase energy are settled by netting against other contracts to sell energy. This netting process is referred to as “book-out” and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. These book-outs reduced both revenues and purchased power and fuel costs in 2003 but did not impact our financial condition, net income or cash flows.

In November 2003, the FASB revised its derivative guidance in DIG Issue No. C15, “Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity.” Effective January 1, 2004, the new guidance changes the criteria for the normal purchases and sales scope exception for electricity contracts. This guidance did not have a material impact on our financial statements.

Cash Flow Hedges

The changes in the fair value of our hedged positions included in the Condensed Consolidated Statements of Income for the three months ended March 31, 2004 and 2003 were comprised of the following (dollars in thousands):

	Three Months Ended March 31, 2004	Three Months Ended March 31, 2003
Gains on the ineffective portion of derivatives qualifying for hedge accounting	$1,384	$2,778
Gains from the change in options' time value excluded from measurement of effectiveness	80	—
Gain from the discontinuance of cash flow hedges	1,137	—

As of March 31, 2004, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions was approximately five years. During the twelve months ending March 31, 2005, we estimate that a net gain of $37 million before income taxes will be reclassified from accumulated other comprehensive income as an offset to the effect on earnings of market price changes for the related hedged transactions.

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

- 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; and

- Marketing and Trading – both non-trading and trading derivative instruments of our competitive business segment.

The following table summarizes our assets and liabilities from risk management and trading activities at March 31, 2004 and December 31, 2003 (dollars in thousands):

March 31, 2004

	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated Electricity:					
Mark-to-market	$ 70,539	$ 15,268	$ (38,305)	$ (872)	$ 46,630
Options at cost and margin account	—	9,539	(18,856)	—	(9,317)
Marketing and Trading:					
Mark-to-market	80,982	149,115	(42,754)	(94,473)	92,870
Emission allowances – at cost	—	1,269	(8,686)	(16,653)	(24,070)
Total	$151,521	$175,191	$(108,601)	$(111,998)	$106,113

December 31, 2003

	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated Electricity:					
Mark-to-market	$44,079	$ 5,900	$(47,268)	$ (3,028)	$ (317)
Options	—	12,101	—	—	12,101
Marketing and Trading:					
Mark-to-market	53,551	116,363	(37,023)	(63,398)	69,493
Emission allowances – at cost	—	4,582	(8,464)	(16,304)	(20,186)
Total	$97,630	$138,946	$(92,755)	$(82,730)	$ 61,091

Cash or other assets may be required to serve as collateral against our open positions on certain energy-related contracts. Collateral provided to counterparties was $1 million at March 31, 2004 and $1 million at December 31, 2003, and is included in investments and other assets on the Condensed Consolidated Balance Sheets. Collateral provided to us by counterparties was $29 million at March 31, 2004 and $12 million at December 31, 2003, and is included in other deferred credits on the Condensed Consolidated Balance Sheets.

Credit 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 represented approximately 28% of our $327 million of risk management and trading assets as of March 31, 2004. Our risk management process assesses and monitors the financial exposure of these 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. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Fair Value Hedges

On January 29, 2004, we entered into two fixed-for-floating interest rate swap transactions on our $300 million 6.4% senior note. The purpose of these hedges is to protect against significant fluctuations in fair value of our debt. Our interest rate swaps are considered to be fully effective with any resulting gains or losses on the derivative offset by a similar loss or gain amount on the underlying fair value of debt. The fair value of the interest rate swaps was $2.9 million at March 31, 2004 and is included in other assets with the corresponding offset in long-term debt less current maturities on the Condensed Consolidated Balance Sheets.

11. Comprehensive Income

Components of comprehensive income for the three months ended March 31, 2004 and 2003, are as follows (dollars in thousands):

	Three Months Ended March 31,	
	2004	2003
Net income	$30,156	$25,298
Other comprehensive income:		
Minimum pension liability adjustment, net of tax	—	31
Unrealized gain on derivative instruments, net of tax (a)	28,886	15,806
Reclassification of realized gain to income, net of tax (b)	(98)	(4,351)
Total other comprehensive income	28,788	11,486
Comprehensive income	$58,944	$36,784

(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

Palo Verde Nuclear Generating Station - Spent Fuel and Waste Disposal

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

Federal Claims. Arizona Public Service Company v. United States of America , United States Court of Federal Claims, 03-2832C.

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. 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. The FERC is still considering the evidence and refund amounts have not yet been finalized. 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.

The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The FERC affirmed the ALJ's conclusion that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. This decision has now been appealed to the Court of Appeals (Ninth Circuit). Although the FERC ruling in the Pacific Northwest matter is being appealed and the FERC has not yet calculated the specific refund amounts due in California, we do not expect that the resolution of these issues, as to the amounts alleged in the proceedings, will have a material adverse impact on our financial position, results of operations or liquidity.

On March 26, 2003, FERC made public a Final Report on Price Manipulation in Western Markets, prepared by its Staff and covering spot markets in the West in 2000 and 2001. The report stated that a significant number of entities who participated in the California markets during the 2000-2001 time period, including APS, may potentially have been involved in arbitrage transactions that allegedly violated certain provisions of the ISO tariff. After reviewing the matter, along with the data supplied by APS, the FERC staff moved to dismiss the claims against APS and to dismiss the proceeding. The motion to dismiss was granted by the FERC on January 22, 2004. Certain parties have sought rehearing of this order, and that request is pending.

PG&E filed for bankruptcy protection in 2001. In the fourth quarter of 2003, the CPUC and the Bankruptcy Court accepted PG&E's plan of reorganization. The plan indicated that PG&E would, at the close of bankruptcy proceedings, be able to pay in full all outstanding, undisputed debts. PG&E emerged from bankruptcy protection on April 12, 2004 and settled all outstanding, undisputed debts with us.

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 California independent system operator 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, which, after moving to state court, has been removed to the federal court for a second time. James Millar, et al. v. Allegheny Energy Supply, et al. , San Francisco Superior Court, Case No. 407867, U.S. District Court (Northern District) C-04-0519 SBA. The First Amended Complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market, in violation of California unfair competition laws. 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 motions continue to be filed, and we currently believe these claims will have no material adverse impact on our financial position, results of operations or liquidity.

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. Pursuant to the terms of a comprehensive settlement entered into in 1996 with El Paso Natural Gas Company, the rates charged for transportation are subject to a rate moratorium through December 31, 2005.

On July 9, 2003 the FERC issued an order that altered the contractual obligations and the rights of parties to the 1996 settlement. In order for APS and Pinnacle West Energy to meet their natural gas supply and capacity requirements, we expect costs to increase by approximately $5 million per year for natural gas supply and by approximately $14 million per year for capacity. APS and Pinnacle West Energy have sought appellate review of the FERC's July 9 order and related issues 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.

Environmental Matters — Superfund

On September 3, 2003, the EPA advised APS and Pinnacle West that the EPA considers APS and Pinnacle West to be a "potentially responsible party" in the Motorola 52 nd Street Superfund Site, Operable Unit 3 (OU3) in Phoenix, Arizona. APS has facilities that are within this superfund site. Liability under Superfund is strict, joint and several. The Company and APS are currently negotiating with the EPA regarding the performance of remedial investigation activities of the APS facilities. Because the ultimate remediation requirements are not yet finalized, we cannot currently estimate the expenditures which may be required.

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. On January 1, 2003, 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 three months ended March 31, 2004 and March 31, 2003.

14. 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. The Price Anderson Act currently limits the combined public liability of nuclear reactor owners to $10.76 billion for claims that could arise from a single nuclear incident. The Palo Verde participants purchase the maximum available commercial insurance of $300 million. The balance of the $10.46 billion is provided 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 property damage, decontamination, and replacement power coverages are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective assessments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The estimated maximum amount of retrospective assessments APS could incur under the current NEIL policies totals $16 million. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

15. Stock-Based Compensation

Pinnacle West offers stock-based compensation plans for officers and key employees of the Company and our subsidiaries. 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 months ended March 31, 2004 and 2003 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 March 31, 2004 (dollars in thousands, except per share amounts):

	Three Months Ended March 31,	
	2004	2003
Net income, as reported	$30,156	$25,298
Add: Stock compensation expense included in reported net income (net of tax)	401	152
Deduct: Total stock compensation expense determined under fair value method (net of tax)	767	452
Pro forma net income	$29,790	$24,998
Earnings per share – basic:		
As reported	$ 0.33	$ 0.28
Pro forma	$ 0.33	$ 0.27
Earnings per share – diluted:		
As reported	$ 0.33	$ 0.28
Pro forma	$ 0.33	$ 0.27

16. Other Income and Other Expense

The following table provides detail of other income and other expense for the three months ended March 31, 2004 and 2003 (dollars in thousands):

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	Three Months Ended March 31,	
	2004	2003
Other income:		
Interest income	$ 3,802	$ 713
Asset sales	3,651	281
Investment gains – net	2,218	1,279
SunCor joint venture earnings	1,185	3,244
Miscellaneous	556	204
Total other income	$11,412	$ 5,721
Other expense:		
Non-operating costs (a)	$ (2,802)	$(2,888)
Asset sales	(2,139)	(650)
Miscellaneous	(1,004)	(659)
Total other expense	$ (5,945)	$(4,197)

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

17. Guarantees

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 consist of equipment and performance guarantees related to our generation construction program, transmission service guarantees for West Phoenix Unit 5 and long-term service agreement guarantees for new power plants. Our credit support instruments enable APS Energy Services to offer commodity energy and energy-related products and enable El Dorado to support the activities of NAC. 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 March 31, 2004 are as follows (dollars in millions):

	Guarantees		Surety Bonds	
	Amount	Term (in years)	Amount	Term (in years)
Parental:				
Pinnacle West Energy	$ 62	1 to 2	$—	—
APS Energy Services	16	1 to 2	38	1
El Dorado (NAC)	40	1 to 2	—	—
Total	$118		$38	

At March 31, 2004, we had entered into approximately $40 million of letters of credit which support various construction agreements. These letters of credit expire in 2004 and 2005. 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. Pinnacle West has approximately $3 million of letters of credit related to workers' compensation expiring in 2004.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At March 31, 2004, approximately $200 million of letters of credit were outstanding to support existing pollution control bonds of approximately $200 million. See Note 4 for more information. 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 $107 million of letters of credit to support certain equity lessors in the Palo Verde sale leaseback transactions (see Note 9 for further details on the Palo Verde sale leaseback transactions). These letters of credit expire in 2005. Additionally, APS has approximately $5 million of letters of credit related to counterparty collateral requirements expiring in 2004. 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.

We provide indemnifications relating to liabilities arising from or related to certain of our agreements. APS has 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 indemnifications and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnifications is likely and therefore no related liability has been recorded.

18. Earnings Per Share

The following table presents earnings per weighted average common share outstanding for the three months ended March 31, 2004 and 2003:

	Three Months Ended March 31,	
	2004	**2003**
Basic earnings per share:		
Income from continuing operations	$0.33	$0.22
Income from discontinued operations	—	0.06
Earnings per share – basic	$0.33	$0.28
Diluted earnings per share:		
Income from continuing operations	$0.33	$0.22
Income from discontinued operations	—	0.06
Earnings per share – diluted	$0.33	$0.28

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 months ended March 31, 2004 and 2003 (in thousands):

	Three Months Ended March 31,	
	2004	**2003**
Weighted-average common shares outstanding – basic	91,294	91,256
Dilutive shares	82	103
Weighted-average common shares outstanding – diluted	91,376	91,359

Options to purchase 2,381,699 shares of common stock at March 31, 2004 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 2,245,211 shares at March 31, 2003.

19. Real Estate Activities – 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) or $0.06 per diluted share. 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.

20. Subsequent Event

In April 2004, the Phoenix Suns Limited Partnership, in which El Dorado holds limited partnership interests, approved the sale of the partnership's assets to a new investor group. The transaction, which is expected to close by June 30, 2004, is subject to various approvals, including National Basketball Association approval. We currently estimate the transaction will result in a gain for El Dorado of approximately $20 million after income taxes.

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

Introduction

We suggest this section be read along with the 2003 Form 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 months ended March 31, 2004 and 2003 are available on our website (www.pinnaclewest.com).

Overview

We own all of the outstanding common stock of APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the state of Arizona. Through its marketing and trading division, APS also generates, sells and delivers electricity to wholesale customers in the western United States. APS has historically accounted for a substantial part of our revenues and earnings. Growth in APS' service territory is about three times the national average and remains a fundamental driver of our revenues and earnings.

Pinnacle West Energy is our unregulated generation subsidiary. We formed Pinnacle West Energy in 1999 as a result of the ACC's requirement that APS transfer all of its competitive assets and services to an affiliate or to a third party by the end of 2002. We planned to transfer APS' generation assets to Pinnacle West Energy. Additionally, Pinnacle West Energy constructed several power plants to meet growing energy needs (1790 MW in Arizona and 570 MW in Nevada). In September 2002, the ACC issued the Track A Order, which prohibited APS from transferring its generation assets to Pinnacle West Energy. As a result of the Track A Order, we are seeking to transfer the plants built by Pinnacle West Energy in Arizona to APS to unite the Arizona generation under one common owner, as originally intended.

SunCor, our real estate development subsidiary, has been and is expected to be an important source of earnings and cash flow, particularly during the years 2003 through 2005 due to accelerated asset sales activity. Our subsidiary, APS Energy Services, provides competitive commodity-related energy services and energy-related products and services to commercial, industrial and institutional retail customers in the western United States.

The marketing and trading division focuses primarily on managing APS' purchased power and fuel risks in connection with APS' costs of serving retail customer energy requirements. We currently expect contributions from our trading activities to be negligible for 2004 and approximately $10 million (pretax) annually thereafter.

We believe APS' general rate case pending before the ACC is the key issue affecting our outlook. See Note 5 in Item 1 for a detailed discussion of this rate case. Other factors affecting our past and future financial results include customer growth; purchased power and fuel costs; operations and maintenance expenses, including those relating to plant outages; weather variations; depreciation and amortization expenses, which are affected by net additions to existing utility plant and other property and changes in regulatory asset amortization; and the expected performance of our subsidiaries, SunCor and El Dorado.

EARNINGS CONTRIBUTIONS BY SUBSIDIARY AND BUSINESS SEGMENTS

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

- our regulated electricity segment, which consists of traditional regulated 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 table summarizes net income and segment details for the three months ended March 31, 2004 and the comparable prior year period for Pinnacle West and each of our subsidiaries (dollars in millions):

Three months ended March 31,	Total		Regulated Electricity		Marketing and Trading		Real Estate (a)		Other	
	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003
APS(b)	$ 33	$ 16	$ 38	$ 14	$ (5)	$ 2	$—	$—	$—	$—
Pinnacle West Energy (b)(c)	(18)	5	(28)	6	10	(1)	—	—	—	—
APS Energy Services	2	8	—	—	1	6	—	—	1	2
SunCor	2	1	—	—	—	—	2	1	—	—
El Dorado (c)	—	3	—	—	—	—	—	—	—	3
Parent company (c)	11	(13)	7	(11)	4	—	—	—	—	(2)
Income from continuing operations	30	20	17	9	10	7	2	1	1	3
Discontinued operations – net of income tax expense	—	5	—	—	—	—	—	5	—	—
Net income	$ 30	$ 25	$ 17	$ 9	$10	$ 7	$ 2	$ 6	$ 1	$ 3

(a) See Note 19.

(b) 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.

(c) Pinnacle West Energy's net income in 2004 and El Dorado's net income (loss) are reported before income taxes. The income tax expense or benefit for these subsidiaries is recorded at the parent company.

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 and APS Energy Services' non-commodity activities. Other gross margin also includes amounts related to APS Energy Services' energy consulting services. In addition, we have reclassified certain prior period amounts to conform to our current period presentation.

Operating Results – Three-month period ended March 31, 2004 compared with the three-month period ended March 31, 2003

Our consolidated net income for the three-months ended March 31, 2004 was $30 million compared with $25 million for the prior year period. The $5 million increase in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment – Net income increased approximately $8 million primarily due to customer growth and favorable weather; lower regulatory asset amortization; and lower purchased power and fuel costs resulting from lower hedged gas and power prices. These positive factors were partially offset by higher costs related to a new power plant placed in service in mid-2003; higher replacement power costs from plant outages due to higher market prices and more unplanned outages; a retail electricity price reduction; higher operations and maintenance costs related to higher customer service costs; and higher depreciation expense related to increased delivery and other assets.

- Marketing and Trading Segment – Net income increased approximately $3 million primarily due to higher forward prices for wholesale electricity, partially offset by lower margins in California of APS Energy Services.

- Real Estate Segment – Net income decreased approximately $4 million primarily due to the 2003 gain on the sale of SunCor's water utility company, which was reported as discontinued operations.

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

	Increase (Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Higher retail sales volumes due to customer growth, excluding weather effects	$13	$ 8
Effects of weather on retail sales	11	7
Decreased purchased power and fuel costs due to lower hedged gas and power prices	8	5
Higher replacement power costs from plant outages due to higher market prices and more unplanned outages	(9)	(5)
Retail electricity price reduction effective July 1, 2003	(6)	(4)
Miscellaneous factors, net	(1)	(1)
Net increase in regulated electricity segment gross margin	16	10
Marketing and trading segment gross margin:		
Higher mark-to-market gains for future delivery due to higher forward prices for wholesale electricity	11	7
Lower competitive retail unit margins in California by APS Energy Services	(8)	(5)
Lower realized margins on wholesale sales primarily due to lower prices and lower volumes	(1)	(1)
Net increase in marketing and trading segment gross margin	2	1
Net increase in regulated electricity and marketing and trading segments' gross margins	18	11
Lower income primarily due to an NAC contract settlement in 2003	(4)	(2)
Higher operations and maintenance expense primarily due to higher customer service costs and new power plants in service	(6)	(4)
Higher interest expense and lower capitalized interest primarily related to new power plants in service	(6)	(3)
Depreciation and amortization decreases (increases):		
New power plants in service	(4)	(2)
Increased delivery and other assets	(5)	(3)
Decreased regulatory asset amortization	13	8
Higher other income net of other expense primarily due to interest income and other	4	2
Miscellaneous items, net	2	3
Net increase in income from continuing operations	$12	10
Discontinued operations related to the first quarter of 2003		(5)
Net increase in net income		$ 5

The increase in net costs related to a new power plant placed in service in mid 2003 by Pinnacle West Energy totaled approximately $7 million after income taxes in the three months ended March 31, 2004 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were $35 million higher for the three-months ended March 31, 2004 compared with the prior year period, primarily as a result of:

- a $23 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- an $18 million increase in retail revenues related to weather; and
- a $6 million decrease in retail revenues related to a reduction in retail electricity prices.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $28 million lower for the three-months ended March 31, 2004 compared with the prior year period, primarily as a result of:

- a $34 million decrease from generation sales other than Native Load primarily due to lower prices and sales volumes;
- $3 million of lower realized wholesale revenues primarily due to lower prices and lower volumes;
- a $2 million decrease from lower competitive retail sales in California by APS Energy Services; and
- $11 million in higher mark-to-market gains for future-period deliveries primarily as a result of higher forward prices for wholesale electricity.

Real Estate Segment Revenues

Real estate segment revenues were $11 million higher for the three months ended March 31, 2004 compared with the prior-year period primarily as a result of increased sales of residential and commercial property and land related to SunCor’s effort to accelerate asset sales.

Other Revenues

Other revenues were $3 million higher for the three-months ended March 31, 2004 compared with the prior year period primarily due to higher APS Energy Services non-commodity revenues, partially offset by lower revenues related to NAC due to a contract settlement in 2003.

Liquidity and Capital Resources

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the three months ended March 31, 2004 and estimated capital expenditures for the next three years (dollars in millions):

	Three Months Ended March 31,	Estimated		
	2004	2004	2005	2006
APS				
Delivery	$ 72	$309	$390	$453
Generation (a)	26	107	160	200
Other(b)	—	20	30	18
Subtotal	98	436	580	671
Pinnacle West Energy (a) (c)	10	61	16	18
SunCor (d)	12	83	27	17
Other (e)	4	1	—	—
Total	$124	$581	$623	$706

(a) As discussed in Note 5 under "APS General Rate Case and Retail Rate Adjustment Mechanisms," as part of its general rate case, APS has requested rate base treatment of the PWEC Dedicated Assets. Pinnacle West Energy actual capital expenditures related to PWEC Dedicated Assets are estimated to be $15 million in 2004, $14 million in 2005 and $14 million in 2006.

(b) Primarily information systems and facilities projects.

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

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

(e) 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 cost. 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. Major transmission projects are driven by strong regional customer growth. APS will begin major projects each year for the next several years, and expects to spend about $200 million on major transmission projects during the 2004 to 2006 time frame. These amounts are included in "APS-Delivery" in the table above. Completion of these projects will stretch from 2005 through at least 2008.

Generation capital expenditures are comprised of various improvements to 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 includes nuclear fuel expenditures of approximately $30 million annually for 2004 to 2006.

Replacement of the steam generators in Palo Verde Unit 2 was completed during the fall outage of 2003 at a cost to APS of approximately $70 million. The Palo Verde owners have approved the manufacture of two additional sets of steam generators. These generators will be installed in Unit 1 (scheduled completion in 2005) and Unit 3 (scheduled completion in 2007). Our portion of steam generator expenditures for Units 1 and 3 is approximately $140 million, which will be spent through 2008. In 2004 through 2006, approximately $90 million of the Unit 1 and Unit 3 costs are included in the generation capital expenditures table above and will be funded with internally-generated cash or external financings.

Contractual Obligations

Our future contractual obligations have not changed materially from the amounts disclosed in Part II, Item 7 of the 2003 Form 10-K with the following exceptions that occurred in the three months ended March 31, 2004:

- Our short-term debt increased approximately $150 million to fund current maturities of long-term debt and provide for other cash needs.
- Our purchased power and fuel commitments increased approximately $68 million with respect to 2004 repayment obligations.
- See Note 4 for a list of payments due on total long-term debt and capitalized lease requirements.

Off-Balance Sheet Arrangements

In 2003, we adopted FIN No. 46R, “Consolidation of Variable Interest Entities,” as it applies to special-purpose entities. FIN No. 46R 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.

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. Based on our assessment of FIN No. 46R, we are not required to consolidate the Palo Verde VIEs.

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 March 31, 2004, APS would have been required to assume approximately $268 million of debt and pay the equity participants approximately $200 million.

In the first quarter of 2004, we adopted FIN No. 46R for all other contractual arrangements. There was no impact to our financial statements.

Guarantees and Letters of Credit

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 and letters of credit.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of May 5, 2004 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. It may also require additional collateral related to certain derivative instruments (see Note 10).

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

APS no longer has any senior secured debt. See "APS" below for a discussion of the termination of APS' mortgage and deed of trust.

Debt Provisions

Pinnacle West's and APS' debt covenants related to their respective financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS comply with these covenants and each anticipates it will continue to meet these and other significant covenant requirements. The ratio of debt to total capitalization cannot exceed 65% for each of the Company and APS individually. At March 31, 2004, the ratio was approximately 52% for Pinnacle West. At March 31, 2004, the ratio was approximately 51% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for each of the Company and APS. The coverages were approximately 4 times for the Company, 4 times for the APS bank financing agreements and 36 times for the APS mortgage indenture at March 31, 2004. 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 loan 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 financial condition or financial prospects.

See Note 4 for further discussions.

Capital Needs and Resources by Company

Pinnacle West (Parent Company)

Our primary cash needs are for dividends to our shareholders; interest payments and optional and mandatory repayments of principal on our long-term debt and equity infusions into our subsidiaries, primarily Pinnacle West Energy. 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. We expect SunCor to make cash distributions to the parent company of $80 to $100 million annually in 2004 and 2005 due to anticipated accelerated asset sales activity. As discussed in Note 5 under "ACC Financing Orders," 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 March 31, 2004, APS' common equity ratio was approximately 48%.

On February 2, 2004, we used proceeds from the $165 million Floating Rate Notes issued on November 12, 2003 and short term borrowings to pay down the maturing $215 million 4.5% Senior Notes due 2004.

Pinnacle West sponsors a pension plan that covers employees of Pinnacle West and our subsidiaries. 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. APS and other subsidiaries fund their share of the pension contribution, of which APS represents approximately 89% 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. The Pension Stability Act was signed into law on April 10, 2004. As a result of this new legislation, our required pension contribution in 2004 is $35 million. We are currently evaluating whether any additional contributions will be made to our pension plans in 2004. We have not yet made any 2004 contributions to our pension plans or other postretirement benefit plans.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See Note 5 for a discussion of the $500 million financing arrangement between APS and Pinnacle West Energy approved by the ACC in 2003.

APS pays for its capital requirements with cash from operations and, to the extent necessary, external financings. APS has historically paid for its dividends to Pinnacle West with cash from operations. See "Pinnacle West (Parent Company)" above for a discussion of common equity ratio that APS must maintain in order to pay dividends to Pinnacle West.

On February 15, 2004, $125 million of APS' 5.875% Notes due 2004 were redeemed at maturity and on March 1, 2004, $80 million of APS' First Mortgage Bonds, 6.625% Series due 2004 were redeemed at maturity. APS used cash from operations and short-term debt to redeem the maturing debt.

On March 31, 2004, the Navajo County, Arizona Pollution Control Corporation issued $166 million of variable interest rate pollution control bonds, 2004 Series A-E, due 2034. The bonds were issued to refinance $166 million of outstanding pollution control bonds. These bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and the Navajo County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Condensed Consolidated Balance Sheets.

Also on March 31, 2004, Coconino County, Arizona Pollution Control Corporation issued $13 million of variable interest rate pollution control bonds, 2004 Series A, due 2034.

The bonds were issued to refinance $13 million of outstanding pollution control bonds. These bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Coconino County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Condensed Consolidated Balance Sheets.

APS has elected to retire all first mortgage bonds issued by APS under its 1946 mortgage and deed of trust, including the first mortgage bonds securing APS senior notes. During the second quarter 2004, APS expects to complete all steps necessary to terminate its existing mortgage and deed of trust and, as a result, will not be able to issue any additional first mortgage bonds under that mortgage.

Although provisions in APS' articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt 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 $1.36 billion has been incurred through March 31, 2004. This does not reflect the proceeds from an anticipated sale in 2004 to SNWA of a 25% interest in the 570 MW Silverhawk Combined Cycle Plant 20 miles north of Las Vegas, Nevada, which would equal about $100 million (plus capitalized interest) of Pinnacle West Energy's cumulative capital expenditures in the 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 three months ended March 31, 2004 and projected capital expenditures for the next three years.

See Note 5 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 three months ended March 31, 2004 and projected capital expenditures for the next three years. 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 2004 and 2005 due to anticipated accelerated asset sales activity.

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 over the next three years and intends to focus on prudently realizing the value of its existing investments.

APS Energy Services' cash requirements during the past three years were funded with cash infusions from the parent company and with cash from operations. See the capital expenditures table above regarding APS Energy Services' actual capital expenditures in the three months ended March 31, 2004 and projected capital expenditures for the next three years.

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 2003 Form 10-K except for the impact of recent accounting pronouncements as discussed in Note 8. See "Critical Accounting Policies" in Item 7 of the 2003 Form 10-K for further details about our critical accounting policies.

Other Accounting Matters

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.

APS General Rate Case

We believe APS' general rate case pending before the ACC is the key issue affecting our outlook. See Note 5 for a detailed discussion of this rate case.

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 remained 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 to be negligible for 2004, and approximately $10 million (pretax) annually thereafter.

Generation Construction Program

See “Liquidity and Capital Resources – Pinnacle West Energy” for information regarding Pinnacle West Energy’s generation construction program, which is nearing completion. The 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 3.4% a year for the three years 2001 through 2003; we currently expect customer growth to average about 3.5% per year from 2004 to 2006. We currently estimate that total retail electricity sales in kilowatt-hours will grow 5.0% on average, from 2004 through 2006, before the retail effects of weather variations. The customer and sales growth referred to in this paragraph applies to Native Load customers. Customer growth for the three-month period ended March 31, 2004 compared with the prior year period was 3.4%.

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.

Operations and Maintenance Expenses Operations and maintenance expenses are impacted by growth, power plant additions and operations, inflation, outages, higher trending pension and other postretirement benefit costs and other factors.

Depreciation and Amortization Expenses Depreciation and amortization expenses are impacted 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 9.3% of assessed value for 2003 and 9.7% for 2002. 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.

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, efforts to accelerate asset sales activities in 2003 were successful. A portion of these sales have been, and additional amounts may be required to be, reported as discontinued operations on our Condensed Consolidated Statements of Income. See Note 19 for further discussion. The annual earnings contribution from SunCor was $56 million after tax in 2003. We anticipate SunCor’s annual earnings contributions in 2004 and 2005 will be in the $30-$40 million range after tax.

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 after tax earnings of $16 million in 2003.

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We expect SunCor and APS Energy Services to have combined earnings of approximately $10 million per year after tax beyond 2005.

El Dorado's historical results are not necessarily indicative of future performance. In addition, we do not currently expect material losses related to NAC in the future. In April 2004, the Phoenix Suns Limited Partnership, in which El Dorado holds limited partnership interests, approved the sale of the partnership's assets to a new investor group. The transaction, which is expected to close by June 30, 2004, is subject to various approvals, including National Basketball Association approval. We currently estimate the transaction will result in a gain for El Dorado of approximately $20 million after income taxes.

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 affecting 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 "predict", "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:

- 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;
- the outcome of regulatory, legislative and judicial proceedings relating to the restructuring;
- the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition;
- market prices for electricity and natural gas;
- power plant performance and outages;
- weather variations affecting local and regional customer energy usage;
- energy usage;
- 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;
- our ability to compete successfully outside traditional regulated markets (including the wholesale market);
- the performance of our marketing and trading activities due to volatile market liquidity and deteriorating counterparty credit and the use of derivative contracts in our business (including the interpretation of the subjective and complex accounting rules related to these contracts);
- changes in accounting principles generally accepted in the United States of America;
- the successful completion of our generation construction program;
- regulatory issues associated with generation construction, such as permitting and licensing;
- the performance of the stock market and the changing interest rate environment, which affect the amount of our required contributions to our pension plan and nuclear decommissioning trust funds, as well as our reported costs of providing pension and other postretirement benefits;
- technological developments in the electric industry;
- the strength of the real estate market in SunCor's market areas, which include Arizona, Idaho, New Mexico and Utah;
- conservation programs; 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.

Interest Rate and Equity Risk

Our major financial market risk exposure is to changing interest rates. Changing interest rates will affect interest paid or variable-rate debt and interest earned by our nuclear decommissioning trust fund. Our policy is to manage interest rates through the use of a combination of fixed rate and floating rate debt.

On January 29, 2004, we entered into two fixed-for-floating interest rate swap transactions on our $300 million 6.4% senior note. These transactions qualify as fair value hedges under SFAS No. 133. See Note 10.

Commodity Price Risk

We are exposed to the impact of market fluctuations in interest rates and 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 instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. Our ERMC, consisting of officers and key management personnel, 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 use such instruments to hedge our exposure to changes in interest rates and 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 transactions. 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.

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:

- 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; and

- Marketing and Trading – non-trading and trading derivative instruments of our competitive business segment.

The following tables show the pretax changes in mark-to-market of our regulated electricity and marketing and trading derivative positions for the three months ended March 31, 2004 and 2003 (dollars in millions):

	Three Months Ended March 31, 2004		Three Months Ended March 31, 2003	
	Regulated Electricity	Marketing and Trading	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at beginning of period	$ —	$ 69	$(49)	$ 57
Change in mark-to-market gains/(losses) for future period deliveries	10	8	5	(8)
Changes in cash flow hedges recorded in OCI	30	17	13	13
Ineffective portion of changes in fair value recorded in earnings	1	1	2	1
Mark-to-market losses/(gains) realized during the period	6	(2)	6	(7)
Mark-to-market of net positions at end of period	$ 47	$ 93	$(23)	$ 56

The tables below show the fair value of maturities of our regulated electricity and trading derivative contracts (dollars in millions) at March 31, 2004 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 2003 Form 10-K for more discussion on our valuation methods.

Regulated Electricity

Source of Fair Value	2004	2005	Years thereafter	Total fair value
Prices actively quoted	$22	$15	$ 5	$42
Prices provided by other external sources	4	1	—	5
Prices based on models and other valuation methods	—	—	—	—
Total by maturity	$26	$16	$ 5	$47

Marketing and Trading

Source of Fair Value	2004	2005	2006	2007	2008	Years thereafter	Total fair value
Prices actively quoted	$12	$—	$ —	$ —	$—	$—	$ 12
Prices provided by other external sources	3	28	32	39	23	—	125
Prices based on models and other valuation methods	6	(6)	(17)	(18)	(7)	(2)	(44)
Total by maturity	$21	$22	$ 15	$ 21	$16	$ (2)	$ 93

The table below shows the impact that hypothetical price movements of 10% would have had on the market value of our risk management and trading assets and liabilities included on the Condensed Consolidated Balance Sheets at March 31, 2004 (dollars in millions).

	March 31, 2004 Gain (Loss)	
Commodity	Price Up 10%	Price Down 10%
Mark-to-market changes reported in earnings (a):		
Electricity	$ (4)	$ 4
Natural gas	1	(1)
Mark-to-market changes reported in OCI (b):		
Electricity	39	(39)
Natural gas	32	(32)
Total	$68	$(68)

(a) These contracts are primarily 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 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 represented approximately 28% of our $327 million of risk management and trading assets as of March 31, 2004. See “Critical Accounting Policies - Mark-to-Market Accounting,” in Item 7 of our 2003 Form 10-K for more discussion on our valuation methods. See Note 10 for further discussion of credit risk.

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 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

See "Environmental Matters—Superfund" in Note 12 of Notes to Condensed Consolidated Financial Statements for a discussion of a superfund site.

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 Part I, Item 1 of the 2003 Form 10-K. We have entered into agreements with various parties to provide backup supplies of water for 2004, 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 2005 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.

Hazardous Air Pollution

EPA recently proposed standards for nickel emissions from oil-fired units. We are currently assessing the need for additional controls to meet the requirements of this proposed standard.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Exhibit No.	Description
12.1	Ratio of Earnings to Fixed Charges
31.1	Certificate of William J. Post, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.2	Certificate of Donald E. Brandt, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended
32.1	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1850, as adopted 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 January 21, 2004	3.1 to the Company's 2003 Form 10-K	1-8962	3-15-04

(b) Reports on Form 8-K

During the quarter ended March 31, 2004, and the period from April 1 through May 7, 2004, we filed the following reports on Form 8-K:

Report dated December 31, 2003 containing exhibits comprised of financial information, earnings variance explanations and an earnings news release (Item 7 and Item 9).

Report dated January 8, 2004 regarding a delay in the schedule for the hearing for APS' pending general rate case (Item 5 and Item 7).

Report dated January 27, 2004 regarding APS' Summary of Responses Received to its Power Supply Resource Request for Proposals dated December 3, 2003 (Item 5 and Item 7).

Report dated January 30, 2004 containing exhibits comprised of a slide presentation for use at an analyst conference (Item 7 and Item 9).

Report dated February 3, 2004 regarding the ACC Staff's and RUCO's initial written testimony filed with the ACC (Item 5).

Report dated April 16, 2004 containing a Procedural Order issued by an ACC ALJ, which revised the procedural schedule and timing of APS' general rate case (Item 5 and 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: May 7, 2004

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)

Index to Exhibits

Exhibits

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99.1	Pinnacle West Risk Factors

Exhibit 12.1

Pinnacle West Capital Corporation
Computation of Earnings to Fixed Charges
($000's)

	Three Months Ended	Twelve Months Ended December 31,				
	3/31/2004	**2003**	**2002**	**2001**	**2000**	**1999**
Earnings:						
Income From Continuing Operations	$ 29,768	$230,576	$206,198	$327,367	$302,332	$269,772
Income Taxes	15,627	105,560	132,228	213,535	194,200	141,592
Fixed Charges	58,465	235,658	219,651	211,958	202,804	194,070
Total	$103,860	$571,794	$558,077	$752,860	$699,336	$605,434
Fixed Charges:						
Interest Expense	$ 50,356	$204,590	$187,512	$175,822	$166,447	$157,142
Estimated Interest Portion of Annual Rents	8,109	31,068	32,139	36,136	36,357	36,928
Total Fixed Charges	$ 58,465	$235,658	$219,651	$211,958	$202,804	$194,070
Ratio of Earnings to Fixed Charges (rounded down)	1.77	2.42	2.54	3.55	3.44	3.11

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 officer 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 first fiscal quarter 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 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: May 7, 2004.

/s/ William J. Post

William J. Post
Chairman and Chief Executive Officer

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 officer 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 first fiscal quarter 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 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: May 7, 2004.

/s/ Donald E. Brandt

Donald E. Brandt
Executive Vice President &
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, William J. Post, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation for the fiscal quarter ended March 31, 2004 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: May 7, 2004.

/s/ William J. Post

William J. Post
Chairman and Chief Executive Officer

I, Donald E. Brandt, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation for the fiscal quarter ended March 31, 2004 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: May 7, 2004.

/s/ Donald E. Brandt

Donald E. Brandt
Executive Vice President and
Chief Financial Officer

Exhibit 99.1

PINNACLE WEST RISK FACTORS
(Report on Form 10-Q for the Fiscal Quarter ending March 31, 2004)

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.

We cannot predict the outcome of APS' general rate case pending before the Arizona Corporation Commission (the "ACC").

As required by a 1999 settlement agreement among Arizona Public Service Company ("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 Corporation ("Pinnacle West Energy") since 1999 to serve APS' retail electricity customers, specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3 (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 electric competition rules (the "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 Rules. If APS does not have a rate adjustment mechanism that allows it to fully recover its power supply costs, then changes in these costs may harm 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 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.

In its filed testimony in the rate case, the ACC staff recommended, among other things, that the ACC decrease APS' rates by approximately 8% (approximately $143 million annually), not allow the PWEC Dedicated Assets to be included in APS' rate base, and not allow APS to recover any of the $234 million written off as a result of the 1999 Settlement Agreement. The ACC staff recommendations, if implemented as proposed, could have a material adverse impact on our results of operations, financial position, liquidity, dividend sustainability, credit ratings, and access to capital markets. We cannot predict the outcome of the rate case and the resulting levels of regulated revenues.

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 ACC's approval of a $500 million financing arrangement between APS and 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 March 31, 2004, APS' common equity ratio was approximately 48%.

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 that 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.

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.

Although the Rules allow retail customers to have access to competitive providers of energy and energy services, under the Rules, 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. 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. 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 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 short-term money markets, longer-term capital markets and the bank 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 rating 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. 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 rating 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, on behalf of a group of owners, 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 and unscheduled outages due to equipment and other problems. We maintain nuclear decommissioning trust funds and external insurance coverage to minimize our financial exposure to some of 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 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 may materially impact our operations, cash flows or financial position.

In a December 1999 order, the FERC established characteristics and functions that must be met by utilities in forming and operating RTOs. The characteristics for an acceptable RTO include independence from market participants, operational control over a region large enough to support efficient and nondiscriminatory markets and exclusive authority to maintain short-term reliability. Additionally, in a pending notice of proposed rulemaking, 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, 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, the results of which are expected to be completed in 2004.

If APS ultimately joins an RTO, APS could incur increased transmission-related costs and reduced transmission service revenues; APS may be required to expand its transmission system according to decisions made by the RTO rather than its internal planning process; and APS may experience other impacts on its operations, cash flows or financial position that will not be quantifiable until the final tariffs and other material terms of the RTO are known.

We are subject to numerous environmental laws and regulations that 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 the 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. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $162 million of regulatory assets on the Consolidated Balance Sheets at March 31, 2004.

- 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, plan funding requirements and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and net periodic cost, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them as necessary.

- 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 common stock equity (as a component of other comprehensive income (loss)).

- 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. Our marketing and trading portfolio consists of structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.