

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion should be read in conjunction with Pinnacle West's Consolidated Financial Statements and the related Notes.

OVERVIEW

Pinnacle West owns 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, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern 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. Customer 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 (1,790 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, APS, through its general rate case currently pending before the ACC, is 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. We refer to these plants as the PWEC Dedicated Assets.

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 and industrial retail customers in the western United States.

El Dorado, our investment subsidiary, sold its investment in NAC on November 18, 2004, which resulted in a pretax gain of \$4 million and the classification of NAC as discontinued operations in 2004. In addition, the year ended December 31, 2004 includes a \$35 million gain (\$21 million after tax) related to the sale of El Dorado's limited partnership interest in the Phoenix Suns.

We continue to focus on solid operational performance in our electricity generation and delivery activities. In the generation area, 2004 represented the thirteenth consecutive year Palo Verde was the largest power producer in the United States. In the delivery area, we focus on superior reliability and customer satisfaction while expanding our transmission and distribution system to meet growth and sustain reliability. We plan to expand long-term resources to meet our retail customers' growing electricity needs.

We believe APS' general rate case pending before the ACC is the key issue affecting our outlook. As discussed in greater detail in Note 3, on August 18, 2004, a substantial majority of the parties to the rate case, including APS, the ACC staff, the Arizona Residential Utility Consumer Office, other customer and advocacy groups, and merchant power plant intervenors entered into the 2004 Settlement Agreement, which proposes terms under which the rate case would be settled. Neither Pinnacle West nor APS is able to predict whether the ACC will approve the 2004 Settlement Agreement as proposed.

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 and transmission outages; weather variations; depreciation and amortization expenses, which are affected by net additions to utility plant and other property and changes in regulatory asset amortization; and the performance of our subsidiaries.

EARNINGS CONTRIBUTIONS 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 (primarily electric service to Native Load customers) 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 income from continuing operations by segment and net income for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
Regulated electricity (a)	\$ 151	\$ 170	\$ 170
Marketing and trading	18	9	58
Real estate	40	45	10
Other (b)	26	2	(1)
Income from continuing operations	235	226	237
Real estate discontinued operations – net of income taxes (c)	4	10	9
Other discontinued operations – net of income taxes (c)	4	5	(31)
Cumulative effect of change in accounting – net of income taxes (d)	–	–	(66)
Net income	<u>\$ 243</u>	<u>\$ 241</u>	<u>\$ 149</u>

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

(b) The year ended 2004 includes a \$35 million gain (\$21 million after-tax) related to the sale of El Dorado's limited partnership interest in the Phoenix Suns.

(c) Discontinued operations relate to NAC and real estate. See Note 22.

(d) Marketing and trading segment change in accounting for trading activities upon adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." See Note 18.

See Note 17 for additional financial information regarding our business segments.

RESULTS OF OPERATIONS

General

Throughout the following explanations of our results of operations, we refer to "gross margin." With respect to our regulated electricity segment and our marketing and trading segment, gross margin refers to electric operating revenues less purchased power and fuel costs. "Gross margin" is a "non-GAAP financial measure," as defined in accordance with SEC rules. "Operating margin" (a GAAP financial measure) plus "other operating expenses," as disclosed in Note 17, is equal to gross margin. We view gross margin as an important performance measure of the core profitability of our operations. This measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses. In addition, we have reclassified certain prior period amounts to conform to our current period presentation.

2004 Compared with 2003

Our consolidated net income for the twelve months ended December 31, 2004 was \$243 million compared with \$241 million for the prior-year period. The \$2 million increase in the period-to-period comparison reflected the following changes in earnings by segment:

- Regulated Electricity Segment – Net income decreased approximately \$19 million primarily due to higher costs (primarily interest expense, depreciation, operation and maintenance costs and property taxes, net of gross margin contributions) related to a new power plant placed in service in mid-2003; increased operations and maintenance costs primarily related to customer service and personnel costs; lower income tax credits; higher depreciation related to delivery and other assets; the effects of milder weather on retail sales; and a retail electricity rate decrease in mid-2003. These negative factors were partially offset by lower regulatory asset amortization, and higher retail sales volumes due to customer growth and usage.

- Marketing and Trading Segment – Net income increased approximately \$9 million primarily due to higher forward and realized prices for wholesale electricity partially offset by lower margins in California by APS Energy Services and increased costs related to a new power plant placed in service in mid-2004.
- Real Estate Segment – Net income decreased approximately \$11 million primarily due to the 2003 gain on the sale of SunCor's water utility company, which was reported as discontinued operations (see Note 22), and decreased asset sales partially offset by increased land sales.
- Other Segment – Net income increased approximately \$23 million primarily due to a \$21 million after-tax gain related to the sale of El Dorado's limited partnership interest in the Phoenix Suns.

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	\$ 43	\$ 26
Lower replacement power costs due to fewer unplanned outages	6	4
Effects of weather on retail sales	(17)	(10)
Retail electricity price reduction effective July 1, 2003	(13)	(8)
Increased purchased power and fuel costs due to higher fuel and power prices	(4)	(2)
Miscellaneous factors, net	(8)	(6)
Net increase in regulated electricity segment gross margin	<u>7</u>	<u>4</u>
Marketing and trading segment gross margin:		
Higher mark-to-market gains for contracts for future delivery due to higher forward prices for wholesale electricity	28	17
Higher realized margins on energy trading primarily due to higher electricity prices	18	11
Increase in generation sales other than Native Load primarily due to higher sales volumes and higher unit volumes	9	5
Lower unit margins and lower competitive retail sales volumes in California by APS Energy Services	(22)	(13)
Net increase in marketing and trading segment gross margin	<u>33</u>	<u>20</u>
Net increase in gross margin for regulated electricity and marketing and trading segments	40	24
Lower real estate segment contributions primarily due to decreased asset sales, a portion of which was recorded in other income in the prior period, partially offset by higher land sales (See Note 22)	(7)	(5)
Higher other income due to the sale of El Dorado's limited partnership interest in the Phoenix Suns	35	21
Higher operations and maintenance expense primarily related to customer service costs, new power plants in service and personnel costs	(48)	(29)
Interest expense net of capitalized financing costs, decreases (increases):		
New power plants in service	(23)	(14)
Lower other debt balances and rates partially offset by increased utility plant in service	9	5
Depreciation and amortization decreases (increases):		
Lower regulatory asset amortization	68	41
New power plants in service	(14)	(8)
Increased delivery and other assets	(20)	(12)
Higher property taxes due to increased plant in service	(12)	(7)
Lower income tax credits	–	(17)
Miscellaneous items, net	8	10
Net increase in income from continuing operations	<u>\$ 36</u>	<u>9</u>
Discontinued operations (primarily real estate segment, see Note 22)		<u>(7)</u>
Net increase in net income		<u>\$ 2</u>

The increase in net costs (primarily interest expense, depreciation and operations and maintenance expense, net of gross margin contributions) related to new power plants placed in service in mid-2003 and mid-2004 by Pinnacle West Energy totaled approximately \$26 million after income taxes in the twelve months ended December 31, 2004 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were \$57 million higher for the twelve months ended December 31, 2004 compared with the prior-year period primarily as a result of:

- a \$101 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- a \$42 million decrease in retail revenues related to milder weather;
- a \$13 million decrease in retail revenues related to a reduction in retail electricity prices; and
- an \$11 million increase due to miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were \$70 million higher for the twelve months ended December 31, 2004 compared with the prior-year period primarily as a result of:

- a \$47 million increase from generation sales other than Native Load primarily due to higher wholesale market prices and higher sales volumes, including sales from the new power plants in service;
- \$28 million in higher mark-to-market gains for future-period deliveries primarily as a result of higher forward prices for wholesale electricity;
- \$20 million of higher energy trading revenues on realized sales of electricity primarily due to higher electricity prices; and
- a \$25 million decrease from lower competitive retail sales volumes in California by APS Energy Services.

Other Revenues

Other revenues were \$15 million higher for the twelve months ended December 31, 2004 compared with the prior-year period primarily due to higher non-commodity revenues at APS Energy Services.

2003 Compared with 2002

Our consolidated net income for the year ended December 31, 2003 was \$241 million compared with \$149 million for the prior year. The 2003 net income included \$15 million of after-tax income from discontinued operations related to NAC and SunCor. The 2002 net income included a \$21 million after-tax loss from discontinued operations related to NAC and SunCor (see Note 22). The 2002 net income also included a \$66 million after-tax charge for the cumulative effect of a change in accounting for trading activities due to the adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (see Note 18). Excluding the discontinued operations and the accounting change, the \$11 million decrease in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment – Income from continuing operations was flat when comparing the two years, due to offsetting factors. Net income in 2003 was negatively impacted by higher purchased power and fuel costs resulting from higher prices for hedged gas and purchased power; higher costs related to new power plants, net of purchased power savings; higher replacement power costs from plant outages due to higher market prices and more unplanned outages (Cholla Unit 3 experienced an unplanned outage from August 3, 2003 through November, 2003 and Units 1 and 2 of the Redhawk Power Plant were substantially restricted for almost one-half of the fourth quarter to correct an equipment design defect); higher operations and maintenance costs related to increased pension and other benefits; two retail electricity price reductions; and higher depreciation expense related to increased delivery and other assets. These negative factors were offset by higher retail sales primarily due to customer growth and favorable weather; the absence of the 2002 write-off of Redhawk Units 3 and 4; lower operating costs primarily related to severance costs recorded in 2002; lower regulatory asset amortization; tax credits and favorable income tax adjustments related to prior years resolved in 2003; and higher income related to APS' return to the AFUDC method of capitalizing construction finance costs.
- Marketing and Trading Segment – Income from continuing operations decreased approximately \$49 million primarily due to lower market liquidity and deteriorating counterparty credit in the wholesale power markets in the western United States.
- Real Estate Segment – Income from continuing operations improved approximately \$35 million primarily due to increased asset, land and home sales.

- Other Segment – Income from continuing operations increased approximately \$3 million primarily due to El Dorado Investment losses recognized in 2002.

Additional details on the major factors that increased (decreased) income from continuing operations and net income for the year ended December 31, 2003 compared with the prior year are contained in the following table (dollars in millions).

	Increase/(Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Increased purchased power and fuel costs primarily due to higher prices for hedged gas and purchased power	\$ (60)	\$ (36)
Higher replacement power costs from plant outages due to higher market prices and more unplanned outages	(47)	(28)
Retail electricity price reductions effective July 1, 2002 and July 1, 2003	(27)	(16)
Higher retail sales volumes due to customer growth, excluding weather effects	48	29
Decreased purchased power costs due to new power plants in service	16	10
Effects of weather on retail sales	13	8
Miscellaneous factors, net	5	2
Net decrease in regulated electricity segment gross margin	<u>(52)</u>	<u>(31)</u>
Marketing and trading segment gross margin:		
Lower mark-to-market gains for future delivery due to lower market liquidity and deteriorating counterparty credit	(59)	(35)
Lower realized margins on wholesale sales primarily due to lower unit margins, partially offset by higher volumes	(32)	(19)
Higher margin related to structured contracts originated in prior years	13	7
Decrease in generation sales other than Native Load primarily due to lower unit margins partially offset by higher sales volumes, including sales from new power plants in service	(7)	(4)
Net decrease in marketing and trading segment gross margin	<u>(85)</u>	<u>(51)</u>
Net decrease in regulated electricity and marketing and trading segments' gross margins	(137)	(82)
Higher income primarily related to El Dorado Investment losses recognized in 2002	8	5
Higher real estate segment contribution primarily due to higher asset, land and home sales	58	36
Operations and maintenance expense decreases (increases):		
Write-off of Redhawk Units 3 and 4 in 2002	47	28
Severance costs recorded in 2002	36	21
Increased pension and other benefit costs	(28)	(17)
Costs for new power plants in service	(20)	(12)
Net other items	1	1
Higher interest expense and lower capitalized interest primarily related to new power plants in service	(26)	(16)
Depreciation and amortization decreases (increases):		
New power plants in service	(19)	(11)
Increased delivery and other assets	(22)	(13)
Decreased regulatory asset amortization	29	17
APS' return to the AFUDC method of capitalizing construction finance costs	8	11
Miscellaneous items, net	5	4
Tax credits and favorable income tax adjustments related to prior years resolved in 2003	–	17
Net decrease in income from continuing operations	<u>\$ (60)</u>	<u>(11)</u>
Discontinued operations (primarily NAC, see Note 22)		37
Increase due to 2002 cumulative effect of a change in accounting for trading activities		<u>66</u>
Net increase in net income		<u>\$ 92</u>

The increase in operating and interest costs related to new power plants placed in service by Pinnacle West Energy, net of purchased power savings and increased gross margin from generation sales other than Native Load, totaled approximately \$30 million after income taxes in the year ended December 31, 2003 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were \$88 million higher in the year ended December 31, 2003 compared with the prior year, primarily as a result of:

- an \$85 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- a \$21 million increase in retail revenues related to weather;
- a \$6 million increase related to traditional wholesale sales as a result of higher prices and higher sales volumes;
- a \$27 million decrease in retail revenues related to two reductions in retail electricity prices; and
- a \$3 million net increase due to miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were \$105 million higher in the year ended December 31, 2003 compared with the prior year, primarily as a result of:

- \$74 million of higher revenues related to the adoption of EITF 02-3 in the fourth quarter of 2002, primarily due to structured contracts that were reported gross in the current period and net in most of the prior period;
- a \$69 million increase from higher competitive retail sales in California by APS Energy Services;
- a \$38 million increase from generation sales other than Native Load primarily due to higher prices and sales volumes, including sales from new power plants in service;
- \$59 million in lower mark-to-market gains for future-period deliveries primarily as a result of lower market liquidity and lower price volatility; and
- \$17 million of lower realized wholesale revenues primarily due to lower unit margins on trading activities that are reported on a net basis.

Real Estate Segment Revenues

Real estate segment revenues were \$161 million higher in the year ended December 31, 2003 compared with the prior year primarily as a result of increased asset, land and home sales related to SunCor's effort to accelerate asset sales.

LIQUIDITY AND CAPITAL RESOURCES**Capital Needs and Resources***Capital Expenditure Requirements*

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

	Actual	Estimated		
	2004	2005	2006	2007
APS				
Delivery	\$ 342	\$ 390	\$ 395	\$ 440
Generation (a)(b)	113	352	158	195
Other (c)	29	30	7	6
Subtotal	484	772	560	641
Pinnacle West Energy (a)	31	7	5	2
SunCor (d)	81	114	61	63
Other	2	8	7	4
Total	\$ 598	\$ 901	\$ 633	\$ 710

- As discussed in Note 3 under "APS General Rate Case; 2004 Settlement Agreement," as part of its general rate case, APS has requested rate base treatment of the PWEC Dedicated Assets. The estimated capital expenditures related to the PWEC Dedicated Assets are reflected in APS for the years 2005, 2006 and 2007.
- The estimate for 2005 includes about \$190 million for acquisition of the Sundance Plant. See "Request for Proposals and Asset Purchase Agreement" in Note 3 for a discussion of the asset purchase agreement between APS and PPL Sundance.
- Primarily information systems and facilities projects.
- Consists primarily of capital expenditures for land development and retail and office building construction reflected in "Real estate investments" on the Consolidated Statements of Cash Flows.

Delivery capital expenditures are comprised of T&D infrastructure additions and upgrades, capital replacements, new customer construction and related information systems and facility costs. Examples of the types of projects included in the forecast include T&D lines and substations, line extensions to new residential and commercial developments and upgrades to customer information systems. Major transmission projects are driven by strong regional customer growth.

Generation capital expenditures are comprised of various improvements to APS' existing fossil and nuclear plants, the acquisition of the Sundance Plant and the replacement of Palo Verde steam generators (see below). 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 2005 to 2007.

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 the fall of 2005) and Unit 3 (scheduled completion in the fall of 2007). Our portion of steam generator expenditures for Units 1 and 3 is approximately \$140 million, which will be spent through 2008. In 2005 through 2007, approximately \$95 million of the costs for steam generator replacements at Units 1 and 3 are included in the generation capital expenditures table above and will be funded with internally-generated cash or external financings.

Contractual Obligations

The following table summarizes Pinnacle West's consolidated contractual requirements as of December 31, 2004 (dollars in millions):

	2005	2006-2007	2008-2009	Thereafter	TOTAL
Long-term debt payments, including interest (a):					
APS	\$ 577	\$ 503	\$ 206	\$ 2,746	\$ 4,032
Pinnacle West	189	305	–	–	494
SunCor	2	9	6	–	17
Total long-term debt payments, including interest	768	817	212	2,746	4,543
Short-term debt payments, including interest (b)	72	–	–	–	72
Capital lease payments	2	3	2	3	10
Operating lease payments	73	139	132	368	712
Minimum pension funding requirement (c)	50	–	–	–	50
Purchase power and fuel commitments (d)	187	171	134	363	855
Purchase obligations (e)	272	16	–	68	356
Nuclear decommissioning funding requirements	11	22	22	146	201
Total contractual commitments	\$ 1,435	\$ 1,168	\$ 502	\$ 3,694	\$ 6,799

(a) The long-term debt matures at various dates through 2034 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using the rates at December 31, 2004.

(b) The short-term debt matures within twelve months. The weighted-average interest rate used to determine interest payments on the short-term debt was 4.21% at December 31, 2004.

(c) Future pension contributions are not determinable for time periods after 2005.

(d) Our purchase power and fuel commitments include purchases of coal, electricity, natural gas and nuclear fuel (see Note 11).

(e) These contractual obligations include commitments for capital expenditures and other obligations. Obligations for 2005 include about \$190 million for acquisition of the Sundance Plant (see Note 3).

Off-Balance Sheet Arrangements

In 1986, APS entered into agreements with three separate VIE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 9 for further information about the sale leaseback transactions. We are not the primary beneficiary of the Palo Verde VIEs and, accordingly, do not consolidate them.

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 December 31, 2004, APS would have been required to assume approximately \$250 million of debt and pay the equity participants approximately \$192 million.

In the first quarter of 2004, we adopted FIN No. 46R, "Consolidation of Variable Interest Entities" for all non-SPE contractual arrangements. SunCor has certain land development arrangements that are required to be consolidated under FIN No. 46R. The assets and non-controlling interests reflected in our Consolidated Balance Sheets related to these arrangements were approximately \$34 million at December 31, 2004.

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 Consolidated Balance Sheets with respect to these obligations. We generally provide indemnifications related to liabilities arising from or related to certain of our agreements, with limited exceptions depending on the particular agreement. See Note 21 for additional information regarding guarantees and letters of credit.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of March 15, 2005 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 18).

	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 "Capital Needs and Resources – By Company – 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 bank 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. These covenants require that the ratio of debt to total capitalization cannot exceed 65% for the Company and for APS. At December 31, 2004, the ratio was approximately 53% for Pinnacle West and 54% 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. Based on 2004 results, the coverages were approximately 4 times for the Company and 4 times for APS. 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, except that Pinnacle West and APS do not have a material adverse change restriction for revolver borrowings equal to outstanding commercial paper amounts.

See Note 6 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 (see the table above for our contractual requirements, including our debt repayment obligations, but excluding optional repayments). On October 20, 2004, our Board of Directors increased the common stock dividend to an indicated annual rate of \$1.90 per share from \$1.80 per share, effective with the December 1, 2004 dividend payment. The level of our common dividends and future dividend growth will be dependent on a number of factors including, but not limited to, payout ratio trends, free cash flow and financial market conditions.

Our primary sources of cash are dividends from APS, external financings and cash distributions from our other subsidiaries, primarily SunCor. For the years 2002 through 2004, total dividends from APS were \$510 million and total cash distributions from SunCor were \$206 million. For the year ended December 31, 2004, dividends from APS were approximately \$170 million and distributions from SunCor were approximately \$85 million. We expect SunCor to make cash distributions to the parent company of approximately \$80 to \$100 million in 2005 based on anticipated asset sales activities. As discussed in Note 3 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 December 31, 2004, APS' common equity ratio as defined was approximately 45%.

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.

At December 31, 2004, the parent company's outstanding long-term debt, including current maturities, was \$468 million. In October 2004, we replaced two separate revolving credit facilities (with collective borrowing capacity of \$275 million) with a \$300 million revolving credit facility that terminates in October 2007. This line of credit is available to support the issuance of up to \$250 million in commercial paper or to be used as bank borrowings, including up to \$100 million for issuances of letters of credit. At December 31, 2004, we had no commercial paper or short-term borrowings outstanding. We ended 2004 in an invested position.

Pinnacle West sponsors a qualified pension plan for the 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. We contributed \$35 million in 2004, \$46 million in 2003, \$27 million in 2002, \$44 million in 2001 and \$24 million in 2000. APS and other subsidiaries fund their share of the pension contribution, of which APS represents approximately 92% of the total funding amounts described above. The assets in the plan are comprised of common stocks, bonds and real estate. Future year contribution amounts are dependent on fund performance and fund valuation assumptions. The minimum required contribution to be made to our pension plan in 2005 is estimated to be approximately \$50 million. The expected contribution to our other postretirement benefit plans in 2005 is estimated to be approximately \$40 million.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "ACC Financing Order" in Note 3 for a discussion of the \$500 million financing arrangement between APS and Pinnacle West Energy authorized by the ACC pursuant to the Financing Order.

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 the 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, 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. The refinanced bonds were all \$25 million of the Navajo 5.50% bonds due 2028 and \$141 million of the Navajo 5.875% bonds due 2028. The Series A-E bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Navajo County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Consolidated Balance Sheets. See Note 6.

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. The refinanced bonds were \$13 million of the Coconino 5.875% bonds due 2028. The Series A 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 Consolidated Balance Sheets. See Note 6.

In May 2004, APS renewed its \$250 million revolving credit facility, while increasing its size to \$325 million and extending its term to three years. The revolver provides liquidity support for APS' \$250 million commercial paper program, as well as an additional \$75 million for other liquidity needs and miscellaneous letters of credit.

On June 29, 2004, APS issued \$300 million of 5.80% senior unsecured notes due June 30, 2014. The proceeds from the sale of the notes were used to redeem \$100 million in aggregate principal amount of APS' 6.25% Notes due January 15, 2005 and a portion of \$300 million in aggregate principal amount of APS' 7.625% Notes due August 1, 2005.

On March 1, 2005, Maricopa County, Arizona Pollution Control Corporation issued \$164 million of variable interest rate pollution control bonds, 2004 Series A-E, due 2029. The bonds were issued to refinance \$164 million of outstanding pollution control bonds. The Series A-E bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Maricopa County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Consolidated Balance Sheets.

APS has retired all first mortgage bonds issued by APS under its 1946 mortgage and deed of trust, including the first mortgage bonds securing APS senior notes. On April 30, 2004, APS terminated its mortgage and deed of trust and, as a result, is not able to issue any additional first mortgage bonds under that mortgage.

APS' outstanding debt was approximately \$2.7 billion at December 31, 2004. APS had committed lines of credit with various banks of \$325 million at December 31, 2004 which were available either to support the issuance of commercial paper or to be used for bank borrowings, including issuances of letters of credit. At December 31, 2004, APS had no outstanding commercial paper or bank borrowings. APS ended 2004 in an invested position.

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

Pinnacle West Energy's capital requirements consist primarily of capital expenditures. In May 2004, SNWA paid Pinnacle West Energy approximately \$91 million for a 25% interest in the 570 MW Silverhawk combined cycle plant. See the capital expenditures table above for actual capital expenditures for 2004 and projected capital expenditures for the next three years. Pinnacle West Energy's sources of cash will be cash infusions from the parent and cash from operations.

See "ACC Financing Order" in Note 3 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 2004 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements with cash from operations and external financings.

In 2004, SunCor did not issue any long-term debt; and it redeemed, refinanced or repaid \$2 million in long-term debt (see Note 6).

SunCor's total outstanding debt was approximately \$87 million as of December 31, 2004. SunCor's total short-term debt was \$71 million at December 31, 2004, including \$35 million of short-term borrowings outstanding under a \$90 million line of credit. SunCor's long-term debt, including current maturities, totaled \$16 million at December 31, 2004.

We expect SunCor to make cash distributions to the parent company of approximately \$80 to \$100 million in 2005 based on anticipated asset sales activities.

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. As described above, during 2004, El Dorado sold its limited partnership interest in the Phoenix Suns and its ownership interest in NAC. 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.

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. We consider the following accounting policies to be our most critical because of 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 our 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 \$135 million of regulatory assets on the Consolidated Balance Sheets at December 31, 2004. A component of the 2004 Settlement Agreement, which is subject to ACC approval, would allow APS to acquire the PWEC Dedicated Assets from Pinnacle West Energy, with a net carrying value of approximately \$850 million, and rate base the PWEC Dedicated Assets at a rate base value of \$700 million. This would result in a mandatory rate base disallowance of approximately \$150 million. As a result, for financial reporting purposes, APS would recognize a one-time, after-tax net plant write-off of approximately \$90 million in the period when the plant transfer to APS is completed and would reduce annual depreciation expense by approximately \$5 million. See Notes 1 and 3 for more information about regulatory assets, APS' general rate case and the 2004 Settlement Agreement.

Pensions and Other Postretirement Benefit Accounting

Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and 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.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the 2004 projected benefit obligation, our 2004 reported pension liability on the Consolidated Balance Sheets and our 2004 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

Actuarial Assumption (a)	Increase/(Decrease)		
	Impact on Projected Benefit Obligation	Impact on Pension Liability	Impact on Pension Expense
Discount rate:			
Increase 1%	\$ (192)	\$ (159)	\$ (8)
Decrease 1%	220	184	8
Expected long-term rate of return on plan assets:			
Increase 1%	–	–	(4)
Decrease 1%	–	–	4

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the 2004 accumulated other postretirement benefit obligation and our 2004 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

Actuarial Assumption (a)	Increase/(Decrease)	
	Impact on Accumulated Other Postretirement Benefit Obligation	Impact on Other Postretirement Benefit Expense
Discount rate:		
Increase 1%	\$ (80)	\$ (4)
Decrease 1%	94	4
Health care cost trend rate (b):		
Increase 1%	96	6
Decrease 1%	(76)	(5)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	–	(1)
Decrease 1%	–	1

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant.

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

See Note 8 for further details about our pension and other postretirement benefit plans.

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 (for contracts designated as normal) or fair value (mark-to-market) accounting. Mark-to-market accounting requires that changes in the fair value are recognized periodically

in income unless certain hedge criteria are met. For fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item associated with the hedged risk are recognized in earnings. For cash flow hedges, changes in the fair value of the derivative are recognized in common stock equity (as a component of other comprehensive income (loss)).

The fair 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 judgement. 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. See "Market Risks – Commodity Price Risk" below for quantitative analysis. See Note 1 for discussion on accounting policies and Note 18 for a further discussion on derivative and energy trading accounting.

OTHER ACCOUNTING MATTERS

Accounting for Derivative and Trading Activities

We adopted EITF 02-3 in the fourth quarter of 2002. We recorded a \$66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Contracts that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

See Notes 1 and 18 for further information on accounting for derivatives.

Variable Interest Entities

See "Liquidity and Capital Resources – Off-Balance Sheet Arrangements" and Note 20 for discussion of VIEs.

FACTORS AFFECTING OUR FINANCIAL OUTLOOK

APS General Rate Case

We believe APS' general rate case, including the proposed settlement pending before the ACC is the key issue affecting our outlook. See "APS General Rate Case; 2004 Settlement Agreement" in Note 3 for a detailed discussion of this rate case and proposed settlement.

Factors Affecting Operating Revenues, Purchased Power and Fuel Costs

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 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 competition.

Customer and Sales Growth The customer and sales growth referred to in this paragraph applies to Native Load customers and sales to them. Customer growth in APS' service territory averaged about 3.4% a year for the three years 2002 through 2004; we currently expect customer growth to average about 3.8% per year from 2005 to 2007. We currently estimate that total retail electricity sales in kilowatt-hours will grow 5.0% on average, from 2005 through 2007, before the effects of weather variations. Customer growth for the year ended December 31, 2004 compared with the prior year was 3.7%.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth and usage patterns. Our experience indicates that a reasonable range of variation in our kilowatt-hour sales projection attributable to such economic factors can result in increases or decreases in annual net income of up to \$10 million.

Retail Rate Changes APS has a rate settlement agreement pending before the ACC that includes, among other things, a proposed general rate increase of 4.21% and a power supply adjuster that would provide timely recovery of variations in purchased power and fuel prices. See "APS General Rate Case; 2004 Settlement Agreement" in Note 3. APS expects to file another general rate case in late 2005.

Weather In forecasting retail sales growth, we assume normal weather patterns based on historical data. Historical extreme weather variations have resulted in annual variations in net income in excess of \$20 million. However, our experience indicates that the more typical variations from normal weather can result in increases or decreases in annual net income of up to \$10 million.

Trading In accordance with GAAP, we adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," in the fourth quarter of 2002. As a consequence, we are recording structured trading transactions completed prior to implementation of EITF 02-3 that do not qualify as derivatives for financial accounting purposes on the accrual method, recognizing the revenues and associated purchased power and fuel costs as the respective commodities are delivered. We expect the deliveries under these historical contracts to contribute the following amounts to net income: approximately \$12 million each year in 2005 through 2007 and approximately \$7 million in 2008.

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, transmission availability or constraints, prevailing market prices, new generating plants being placed in service and our hedging program for managing such costs. See "Natural Gas Supply" in Note 11 for more information on fuel costs. See "APS General Rate Case; 2004 Settlement Agreement" in Note 3 for information regarding a power supply adjuster.

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.

Other Factors Affecting Financial Results

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 utility plant and other property, which includes generation construction or acquisition, and changes in regulatory asset amortization. Silverhawk was placed in service in May 2004. APS plans to acquire the Sundance Plant in 2005 and, in accordance with the proposed rate settlement, to issue requests for proposals to acquire additional long-term resources in 2006 and 2007. As part of the 1999 Settlement Agreement, APS amortized certain regulatory assets over a period that ended June 30, 2004. Amortization in the last three years is as follows (dollars in millions):

2002	2003	2004
\$115	\$86	\$18

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 9.2% of assessed value for 2004 and 9.3% for 2003. We expect property taxes to increase primarily due to our generation construction program, as the plants phase-in to the property tax base, the planned acquisition of the Sundance Plant 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, 2003 and 2004. Interest expense is also affected by interest rates on variable-rate debt and interest rates on the refinancing of the Company's future liquidity needs. In addition, see Note 1 for a discussion of AFUDC.

Retail Competition The regulatory developments and legal challenges to the Rules discussed in Note 3 have raised considerable uncertainty about the status and pace of retail electric competition 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 2004 were successful. A portion of these sales have been, and additional amounts may be required to be, reported as discontinued operations on our Consolidated Statements of Income. SunCor's net income was \$45 million in 2004. See Note 22 for further discussion. We anticipate SunCor's earnings contributions in 2005 to be approximately \$50 million after income taxes.

El Dorado's historical results are not indicative of future performance. El Dorado's income before taxes in 2004 was \$40 million. Income taxes were recorded at the parent company. The year ended 2004 includes a \$35 million gain (\$21 million after tax) related to the sale of El Dorado's limited partnership interest in the Phoenix Suns. El Dorado sold its investment in NAC on November 18, 2004, which resulted in a pretax gain of \$4 million and is classified as discontinued operations in 2004 and prior years. See Note 22 for information regarding the sale of NAC.

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

Market Risks

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

Interest Rate and Equity Risk

Our major financial market risk exposure is to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our nuclear decommissioning trust fund (see Note 12). 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 6.

The tables below present contractual balances of our consolidated long-term and short-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 2004 and 2003. The interest rates presented in the tables below represent the weighted-average interest rates for the years ended December 31, 2004 and 2003 (dollars in thousands):

	2004					
	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2005	4.21%	\$ 71,030	1.81%	\$ 214,967	7.27%	\$ 402,198
2006	-	-	6.55%	2,918	6.45%	395,314
2007	-	-	4.81%	302	5.99%	1,154
2008	-	-	5.22%	5,294	5.51%	1,055
2009	-	-	-	-	5.51%	818
Years thereafter	-	-	1.31%	516,340	4.79%	1,669,901
Total		\$ 71,030		\$ 739,821		\$ 2,470,440
Fair value		\$ 71,030		\$ 740,271		\$ 2,574,608

	2003					
	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2004	4.26%	\$ 86,081	1.57%	\$ 280,749	5.33%	\$ 424,165
2005	-	-	1.99%	165,469	7.27%	403,204
2006	-	-	6.55%	2,937	6.49%	391,585
2007	-	-	4.99%	373	5.54%	1,256
2008	-	-	5.19%	5,269	5.55%	1,098
Years thereafter	-	-	1.84%	106,520	5.83%	1,547,775
Total		<u>\$ 86,081</u>		<u>\$ 561,317</u>		<u>\$ 2,769,083</u>
Fair value		<u>\$ 86,081</u>		<u>\$ 561,447</u>		<u>\$ 2,913,085</u>

The tables below present contractual balances of APS' long-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 2004 and 2003. The interest rates presented in the tables below represent the weighted-average interest rates for the years ended December 31, 2004 and 2003 (dollars in thousands):

	2004			
	Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount
2005	1.22%	\$ 49,520	7.27%	\$ 401,727
2006	-	-	6.72%	86,082
2007	-	-	5.51%	867
2008	-	-	5.51%	1,054
2009	-	-	5.51%	818
Years thereafter	1.31%	516,340	4.79%	1,669,901
Total		<u>\$ 565,860</u>		<u>\$ 2,160,449</u>
Fair value		<u>\$ 565,799</u>		<u>\$ 2,254,061</u>

	2003			
	Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount
2004	1.57%	\$ 280,340	6.16%	\$ 206,727
2005	-	-	7.27%	402,259
2006	-	-	6.73%	85,451
2007	-	-	5.55%	1,134
2008	-	-	5.55%	1,098
Years thereafter	1.84%	106,520	5.83%	1,547,775
Total		<u>\$ 386,860</u>		<u>\$ 2,244,444</u>
Fair value		<u>\$ 386,906</u>		<u>\$ 2,365,821</u>

Commodity Price Risk

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity 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 purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

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 non-trading and trading derivative positions in 2004 and 2003 (dollars in millions):

	2004		2003	
	Regulated Electricity	Marketing and Trading	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at beginning of year	\$ -	\$ 69	\$ (49)	\$ 57
Change in mark-to-market gains/(losses) for future period deliveries	11	21	(5)	(7)
Changes in cash flow hedges recorded in OCI	43	37	41	44
Ineffective portion of changes in fair value recorded in earnings	(2)	1	8	-
Mark-to-market losses/(gains) realized during the year	(18)	(21)	5	(25)
Mark-to-market of net positions at end of year	<u>\$ 34</u>	<u>\$ 107</u>	<u>\$ -</u>	<u>\$ 69</u>

The tables below show the fair value of maturities of our non-trading and trading derivative contracts (dollars in millions) at December 31, 2004 by maturities and by the type of valuation that is performed to calculate the fair values. See Note 1, "Derivative Accounting," for more discussion of our valuation methods.

Regulated Electricity

Source of Fair Value	2005	2006	2007	Total Fair Value
Prices actively quoted	\$ 27	\$ 10	\$ (2)	\$ 35
Prices provided by other external sources	-	-	-	-
Prices based on models and other valuation methods	(1)	-	-	(1)
Total by maturity	<u>\$ 26</u>	<u>\$ 10</u>	<u>\$ (2)</u>	<u>\$ 34</u>

Marketing and Trading

Source of Fair Value	2005	2006	2007	2008	2009	Years Thereafter	Total Fair Value
Prices actively quoted	\$ 44	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 44
Prices provided by other external sources	1	32	42	24	(1)	(2)	96
Prices based on models and other valuation methods	(9)	(6)	(13)	(6)	-	1	(33)
Total by maturity	<u>\$ 36</u>	<u>\$ 26</u>	<u>\$ 29</u>	<u>\$ 18</u>	<u>\$ (1)</u>	<u>\$ (1)</u>	<u>\$ 107</u>

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management and trading assets and liabilities included on Pinnacle West's Consolidated Balance Sheets at December 31, 2004 and 2003 (dollars in millions).

	December 31, 2004		December 31, 2003	
	Gain (Loss)		Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Commodity				
Mark-to-market changes reported in earnings (a):				
Electricity	\$ (4)	\$ 4	\$ (2)	\$ 2
Natural gas	2	(2)	(1)	1
Other	1	(1)	1	-
Mark-to-market changes reported in OCI (b):				
Electricity	35	(35)	36	(36)
Natural gas	43	(43)	30	(30)
Total	<u>\$ 77</u>	<u>\$ (77)</u>	<u>\$ 64</u>	<u>\$ (63)</u>

(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 represents approximately 35% of Pinnacle West's \$391 million of risk management and trading assets as of December 31, 2004. See Note 1, "Derivative Accounting" for a discussion of our credit valuation adjustment policy. See Note 18 for further discussion of credit risk.

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 "estimate," "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, including transmission outages and constraints;
- weather variations affecting local and regional customer energy usage;
- customer growth and 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;

- the uncertainty that current credit ratings will remain in effect for any given period of time;
- 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 any 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 and the interpretation of those principles;
- the performance of the stock market and the changing interest rate environment, which affect the amount of required contributions to Pinnacle West's pension plan and APS' 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; and
- other uncertainties, all of which are difficult to predict and many of which are beyond the control of Pinnacle West.