

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

INTRODUCTION

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

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 substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. 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 earnings contributions of our marketing and trading segment significantly decreased over the past two years due to lower market liquidity and deteriorating counterparty credit in the wholesale power markets 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 continue to focus on solid operational performance in our electricity generation and delivery activities. In the generation area, 2003 represented the twelfth consecutive year Palo Verde was the largest power producer in the United States. In the delivery area, we focus on superior reliability and expanding our transmission and distribution system to meet growth and sustain reliability.

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, in this rate case APS has requested, among other things, a 9.8% retail rate increase (approximately \$175 million annually) rate treatment for the PWEC Dedicated Assets and the recovery of \$234 million written off by APS as part of the 1999 Settlement Agreement. In its filed testimony, 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 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 hearing on the rate case is scheduled to begin on May 25, 2004. We believe the ACC will be able to make a decision by the end of 2004.

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 products, 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. In early 2003, we moved our marketing and trading activities to APS from Pinnacle West (existing wholesale contracts

remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy; and

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

The following tables summarize net income and segment details for the years ended December 31, 2003, 2002 and 2001 for Pinnacle West and each of our subsidiaries (dollars in millions):

2003	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate(a)	Other(b)
APS (c)	\$ 181	\$ 184	\$ (3)	\$ -	\$ -
Pinnacle West Energy (c)	(1)	-	(1)	-	-
APS Energy Services	16	-	13	-	3
SunCor	46	-	-	46	-
El Dorado (principally NAC) (d)	7	-	-	-	7
Parent company (d)	(18)	(14)	-	(1)	(3)
Income from continuing operations	231	170	9	45	7
Income from discontinued operations – net of income taxes	10	-	-	10	-
Net income	\$ 241	\$ 170	\$ 9	\$ 55	\$ 7

2002	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate(a)	Other(b)
APS (c)	\$ 199	\$ 198	\$ 1	\$ -	\$ -
Pinnacle West Energy (c) (e)	(19)	(21)	2	-	-
APS Energy Services (d)	28	-	23	-	5
SunCor	10	-	-	10	-
El Dorado (principally NAC) (d)	(55)	-	-	-	(55)
Parent company (d)	43	(7)	32	-	18
Income (loss) from continuing operations	206	170	58	10	(32)
Income from discontinued operations – net of income taxes	9	-	-	9	-
Cumulative effect of change in accounting – net of income taxes (f)	(66)	-	(66)	-	-
Net income (loss)	\$ 149	\$ 170	\$ (8)	\$ 19	\$ (32)

2001	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate(a)	Other
APS (c)	\$ 281	\$ 139	\$ 142	\$ -	\$ -
Pinnacle West Energy (c)	18	18	-	-	-
APS Energy Services (d)	(10)	-	(11)	-	1
SunCor	3	-	-	3	-
El Dorado (d)	-	-	-	-	-
Parent company (d)	35	(5)	40	-	-
Income before accounting change	327	152	171	3	1
Cumulative effect of change in accounting – net of income taxes (g)	(15)	(15)	-	-	-
Net income	\$ 312	\$ 137	\$ 171	\$ 3	\$ 1

(a) See Note 22, "Real Estate Activities – Discontinued Operations."

(b) The "Other" segment primarily includes activities related to El Dorado's investment in NAC. We recorded pretax losses of \$59 million in 2002, primarily related to NAC contracts with three customers.

- (c) Consistent with APS' October 2001 ACC filing, APS entered into contracts with its affiliates to buy power through June 2003. The contracts reflected prices based on the fully-dispatchable dedication of the PWEC Dedicated 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 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 3 for more information.
- (d) APS Energy Services' net income prior to 2003 and El Dorado's net income (loss) are primarily reported before income taxes. The income tax expense or benefit for these subsidiaries is recorded at the parent company.
- (e) In the fourth quarter of 2002 Pinnacle West Energy recorded a charge related to the cancellation of Redhawk Units 3 and 4 of approximately \$30 million after income taxes (\$49 million pretax).
- (f) As of October 1, 2002, we recorded a \$66 million after-tax charge for the cumulative effect of a change in accounting for trading activities, for the early adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." See Note 18.
- (g) APS recorded a \$15 million after-tax charge in 2001 for the cumulative effect of a change in accounting for derivatives related to the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." See Note 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. Our real estate segment gross margin refers to real estate revenues less real estate operations costs of SunCor. Other gross margin refers to other operating revenues less other operating expenses, which primarily includes El Dorado's investment in NAC, which we began consolidating in our financial statements in July 2002. Other gross margin also includes amounts related to APS Energy Services' energy consulting services. In addition, we have reclassified certain prior period amounts to conform to our current period presentation, including netting of certain revenues and purchased power amounts as a result of the adoption of 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" (see Note 18).

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 2002 net income includes 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 accounting change, the \$26 million increase in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment – Net income 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 (Unit 3 of the Cholla Power Plant 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 – Net income improved approximately \$36 million primarily due to increased asset, land and home sales.
- Other Segment – Net income increased approximately \$39 million primarily due to NAC 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	(52)	(31)
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	(85)	(51)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(137)	(82)
Higher income primarily related to NAC losses recognized in 2002	66	40
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	(24)	(14)
Decreased regulatory asset amortization	29	17
APS' return to the AFUDC method of capitalizing construction finance costs	8	11
Miscellaneous items, net	7	7
Tax credits and favorable income tax adjustments related to prior years resolved in 2003	-	17
Net (decrease)/increase in income from continuing operations	\$ (2)	26
Increase due to 2002 cumulative effect of a change in accounting for trading activities – net of income taxes		66
Net increase in net income		\$ 92

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.

Other Revenues

Other revenues were \$24 million higher in the year ended December 31, 2003 compared with the prior year primarily due to our consolidation of NAC's financial statements beginning in the third quarter of 2002, partially offset by decreased sales activity at NAC.

2002 Compared with 2001

Our consolidated net income for the year ended December 31, 2002 was \$149 million compared with \$312 million for the prior year. We recognized a \$66 million after-tax charge in 2002 for the cumulative effect of a change in accounting for trading activities for the early adoption of EITF 02-3 on October 1, 2002 (see Note 18). In 2001, we recognized a \$15 million after-tax charge for the cumulative effect of a change in accounting for derivatives, as required by SFAS No. 133 (see Note 18). Net income for 2002 includes income from discontinued operations of \$9 million after-tax related to our real estate segment (see Note 22). Excluding the accounting changes and discontinued operations, the \$121 million decrease in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment – Income from continuing operations increased \$18 million primarily due to lower replacement power costs for power plants outages, retail customer growth and higher average customer usage. These positive factors were partially offset by a write-off of Redhawk Units 3 and 4, higher operating costs primarily related to severance costs recorded in 2002, retail electricity price decreases, the effects of milder weather, and higher costs for purchased power and gas due to higher hedged gas and power prices.
- Marketing and Trading Segment – Income from continuing operations decreased \$113 million primarily due to lower liquidity and lower price volatility in the wholesale power markets in the western United States.
- Other Segment – Net income decreased approximately \$33 million, primarily due to 2002 losses related to our investment in NAC.
- Real Estate Segment – Income from continuing operations increased by \$7 million primarily due to increased asset, land and home sales.

Additional details on the major factors that increased (decreased) income from continuing operations and net income for the year ended December 31, 2002 compared with the prior year are contained in the following table (dollars in millions).

	Increase/(Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages	\$ 127	\$ 76
Higher retail sales volumes due to customer growth and higher average usage, excluding weather effects	38	23
2001 charges related to purchased power contracts with Enron and its affiliates	13	8
Retail price reductions effective July 1, 2001 and July 1, 2002	(28)	(17)
Effects of milder weather on retail sales	(27)	(16)
Increased purchased power and fuel costs due to higher hedged gas and power prices, partially offset by improved hedge management, net of mark-to-market reversals	(9)	(5)
Miscellaneous factors, net	(2)	(2)
Net increase in regulated electricity segment gross margin	112	67
Marketing and trading segment gross margin:		
Lower realized wholesale margins net of related mark-to-market reversals due to lower prices and volumes	(91)	(55)
Lower mark-to-market gains for future delivery due to lower market liquidity and lower price volatility	(76)	(45)
Decrease in generation sales other than Native Load due to lower market prices partially offset by higher sales volumes	(66)	(40)
Higher competitive retail sales in California by APS Energy Services	32	19
2001 write-off of prior period mark-to-market value related to trading with Enron and its affiliates	8	5
Lower mark-to-market reversals due to the adoption of EITF 02-3	8	5
Net decrease in marketing and trading segment gross margin	(185)	(111)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(73)	(44)
Lower other gross margin primarily related to NAC losses	(44)	(26)
Higher operations and maintenance expense related to a \$47 million write-off of Redhawk Units 3 and 4 and 2002 severance costs of approximately \$36 million, partially offset by lower generation reliability costs	(54)	(32)
Higher taxes other than income taxes	(7)	(4)
Lower other income primarily due to a 2001 insurance recovery of environmental remediation costs	(12)	(7)
Higher net interest expense primarily due to higher debt balances and lower capitalized interest	(16)	(10)
Miscellaneous factors, net	4	2
Net decrease in income from continuing operations	\$ (202)	(121)
Decrease due to 2002 cumulative effect of change in accounting for trading activities – net of income taxes		(66)
Increase due to 2001 cumulative effect of change in accounting for derivatives – net of income taxes		15
Increase due to 2002 discontinued operations – net of income taxes		9
Net decrease in net income		\$ (163)

Regulated Electricity Segment Revenues

Regulated electricity segment revenues related to our regulated retail and wholesale electricity businesses were \$94 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- a \$64 million decrease in revenues related to traditional wholesale sales as a result of lower sales volumes and lower prices;
- a \$60 million decrease in retail revenues related to milder weather;
- a \$69 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- a \$28 million decrease in retail revenues related to reductions in retail electricity prices; and
- an \$11 million decrease due to other miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were \$183 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- a \$98 million decrease in revenues from generation sales other than Native Load primarily due to lower market prices partially offset by higher sales volumes;
- \$131 million of lower realized wholesale revenues net of related mark-to-market reversals primarily due to lower prices partially offset by higher volumes;
- a \$105 million increase in revenues from higher competitive retail sales in California by APS Energy Services;
- an \$8 million increase in revenues due to the absence of a 2001 write-off of prior period mark-to-market value related to trading with Enron and its affiliates;

- \$8 million of higher revenues related to the adoption of EITF 02-3; and
- \$75 million of lower mark-to-market gains for future delivery primarily as a result of lower market liquidity and lower price volatility, resulting in lower volumes.

Real Estate Segment Revenues

Real Estate segment revenues were \$32 million higher in the year ended December 31, 2002 compared with the prior year primarily as a result of increased land, asset and home sales.

Other Revenues

Other revenues were \$50 million higher in the year ended December 31, 2002 compared with the prior year primarily due to the consolidation of NAC's financial statements beginning in the third quarter of 2002.

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, 2003 and estimated capital expenditures for the next three years (dollars in millions):

	Actual	Estimated		
	2003	2004	2005	2006
APS				
Delivery	\$ 288	\$ 309	\$ 390	\$ 453
Generation (a)	136	107	160	200
Other	5	10	12	2
Subtotal	429	426	562	655
Pinnacle West Energy (a)(b)	250	61	24	4
SunCor (c)	72	83	27	17
Other (d)	16	11	18	16
Total	\$ 767	\$ 581	\$ 631	692

(a) As discussed in Note 3 under "APS General Rate Case and Retail Rate Adjustment Mechanisms," as part of its 2003 general rate case, APS requested rate base treatment of the PWEC Dedicated Assets. Pinnacle West Energy actual capital expenditures related to PWEC Dedicated Assets were \$49 million for 2003 and are estimated to be \$15 million in 2004, \$21 million in 2005 and \$4 million in 2006.

(b) 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.

(c) 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.

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

Delivery capital expenditures are comprised of T&D infrastructure additions and upgrades, capital replacements, new customer construction and related information systems and facility costs. Examples of the types of projects included in the forecast include T&D lines and substations, line extensions to new residential and commercial developments and upgrades to customer information systems. APS completed the Southwest Valley transmission project in 2003 at a cost of approximately \$70 million. 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

The following table summarizes contractual requirements as of December 31, 2003 (dollars in millions):

	2004	2005-2006	2007-2008	Thereafter	TOTAL
Long-term debt payments, including interest: (a)					
APS	\$ 342	\$ 699	\$ 192	\$ 2,567	\$ 3,800
Pinnacle West	242	497	–	–	739
SunCor	4	12	5	–	21
El Dorado	1	1	–	–	2
Short-term debt payments, including interest (b)	88	–	–	–	88
Capital lease payments	3	5	2	3	13
Operating lease payments	73	138	132	421	764
Minimum pension funding requirement (c)	100	–	–	–	100
Purchase power and fuel commitments (d)	209	134	102	461	906
Purchase obligations (e)	85	22	5	68	180
Nuclear decommissioning funding requirements	11	22	22	158	213
Total contractual commitments	\$ 1,158	\$ 1,530	\$ 460	\$ 3,678	\$ 6,826

- (a) The long-term debt matures at various dates through fiscal year 2034 and bears interest principally at fixed rates. Interest on variable long-term debt is set at the December 31, 2003 rates. The short-term debt matures within 12 months. The weighted-average interest rate of the short-term debt is 4.26% at December 31, 2003.
- (b) The short-term debt matures within 12 months. The weighted-average interest rate of the short-term debt is 4.26% at December 31, 2003.
- (c) If currently pending legislation is enacted, our required pension contribution in 2004 would decrease to the \$25 to \$50 million range. Future pension contributions are not determinable for time periods after 2004.
- (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.

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. See Note 9 for further information about the sale leaseback transactions. Based on our assessment of FIN No. 46R, we are not required to consolidate the Palo Verde VIEs. Certain provisions of FIN No. 46R have a future effective date. We do not expect these provisions to have a material impact on our financial statements.

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, 2003, APS would have been required to assume approximately \$268 million of debt and pay the equity participants approximately \$200 million.

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. 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 11, 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 18).

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

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 the covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65% for each of the Company and APS individually. At December 31, 2003, the ratio was approximately 54% for Pinnacle West. At December 31, 2003, the ratio was approximately 53% 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 2003 results, the coverages were approximately 4 times for the Company, 4 times for the APS bank financing agreements and 15 times for the APS mortgage indenture. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

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.

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) and equity infusions into our subsidiaries, primarily Pinnacle West Energy. On October 22, 2003, our board of directors increased the common stock dividend to an indicated annual rate of \$1.80 per share from \$1.70 per share, effective with the December 1, 2003 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 2001 through 2003, total dividends from APS were \$510 million and total distributions from SunCor were \$121 million. For the year ended December 31, 2003, dividends from APS were approximately \$170 million and distributions from SunCor were approximately \$108 million. 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 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, 2003, APS' common equity ratio was approximately 46%.

On May 12, 2003, APS issued \$500 million of debt as follows: \$300 million aggregate principal amount of its 4.65% Notes due 2015 and \$200 million aggregate principal amount of its 5.625% Notes due 2033. Also on May 12, 2003, APS made a \$500 million loan to Pinnacle West Energy, and Pinnacle West Energy distributed the net proceeds of that loan to us to fund our repayment of a portion of the debt incurred to finance the construction of the PWEC Dedicated Assets. See "ACC Financing Order" in Note 3 for additional information. With Pinnacle West Energy's distribution to us on May 12, 2003, we repaid the outstanding balance (\$167 million) under a credit facility. We used a portion of the remaining proceeds to redeem our \$250 million Floating Rate Notes due 2003 on June 2, 2003 and to repay other short-term debt. On November 12, 2003, we issued \$165 million of our Floating Rate Senior Notes due 2005.

At December 31, 2003, the parent company's outstanding long-term debt, including current maturities, was \$681 million. At December 31, 2003, we had unused credit commitments from various banks totaling \$275 million, which were available to support the issuance of commercial paper or to be used as bank borrowings. At December 31, 2003, we had no commercial paper outstanding and no short-term borrowings. We ended 2003 in an invested position.

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. We elected to contribute cash to our pension plan in each of the last five years; our minimum required contributions during each of those years was zero. Specifically, we contributed \$73 million for 2002 (\$46 million of which was contributed in June 2003); \$24 million for 2001; \$44 million for 2000 (\$20 million of

which was contributed in 2001); and \$25 million for 1999. 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. Under current law, we are required to contribute approximately \$100 million to our pension plans in 2004 and expect to contribute approximately \$50 million to our other postretirement benefit plan in 2004. If currently pending legislation is enacted, our required pension contribution in 2004 would decrease to the \$25 to \$50 million range.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "Pinnacle West (Parent Company)" above and Note 3 for discussion of the \$500 million financing arrangement between APS and Pinnacle West Energy approved by the ACC in 2003 and discussion of a \$125 million financing arrangement between APS and Pinnacle West.

APS pays for its capital requirements with cash from operations and, to the extent necessary, external financings. APS has historically 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 April 7, 2003, APS redeemed approximately \$33 million of its First Mortgage Bonds, 8% Series due 2025, and on August 1, 2003, APS redeemed approximately \$54 million of its First Mortgage Bonds, 7.25% Series due 2023.

On 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.

APS' outstanding debt was approximately \$2.6 billion at December 31, 2003. At December 31, 2003, APS had unused credit commitments from various banks totaling about \$250 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At December 31, 2003, APS had no outstanding commercial paper or bank borrowings. APS ended 2003 in an invested position.

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

Pinnacle West Energy

The costs of Pinnacle West Energy's construction of 2,360 MW of generating capacity from 2000 through 2004 are expected to be about \$1.4 billion, of which \$1.35 billion has been incurred through December 31, 2003. 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 2003 and projected capital expenditures for the next three years.

See Note 3 and "Pinnacle West (Parent Company)" above for a discussion of the \$500 million financing arrangement between APS and Pinnacle West Energy authorized by the ACC pursuant to the Financing Order.

Other Subsidiaries

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

In 2003, SunCor acquired or issued \$10 million in long-term debt, and redeemed, refinanced or repaid \$1 million in long-term debt (see Note 6).

SunCor's outstanding long and short-term debt was approximately \$104 million as of December 31, 2003. SunCor's total short-term debt was \$86 million at December 31, 2003. SunCor had a \$120 million line of credit, under which \$50 million of short-term borrowings were outstanding at December 31, 2003. SunCor's long-term debt, including current maturities, totaled \$18 million at December 31, 2003.

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 for 2003 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. 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 \$165 million of regulatory assets on the Consolidated Balance Sheets at December 31, 2003. See Notes 1 and 3 for more information about regulatory assets and APS' general rate case.

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 2003 projected benefit obligation, our 2003 reported pension liability on the Consolidated Balance Sheets and our 2003 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on our 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%	\$ (165)	\$ (123)	\$ (8)
Decrease 1%	189	139	6
Expected long-term rate of return on plan assets:			
Increase 1%	–	–	(3)
Decrease 1%	–	–	3

(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 2003 accumulated other postretirement benefit obligation and our 2003 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on our Consolidated Statements of Income (dollars in millions):

Actuarial Assumption (a)	Increase/(Decrease)	
	Impact on Accumulated Postretirement Benefit Obligation	Impact on Other Postretirement Benefit Expense
Discount rate:		
Increase 1%	\$ (81)	\$ (5)
Decrease 1%	96	5
Health care cost trend rate (b):		
Increase 1%	95	7
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 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)). See "Market Risks – Commodity Price Risk" below for quantitative analysis. See Note 18 for a further discussion on derivative and energy trading accounting.

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. 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 03-11 effective October 1, 2003. EITF 03-11 provides guidance on whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported on a net or gross basis and concluded 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 netted against other contracts to sell energy. This is called “book-out” and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We netted these book-outs reducing both revenues and purchased power and fuel costs in 2003, 2002 and 2001, but this did not impact our financial condition, net income or cash flows.

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.

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

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

Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, “Accounting for Asset Retirement Obligations.” The standard requires the fair value of asset retirement obligations to be recorded as a liability, along with an offsetting plant asset, when the obligation is incurred. Accretion of the liability due to the passage of time is an operating expense and the capitalized cost is depreciated over the useful life

of the long-lived asset. (See Note 1 for more information regarding our previous accounting for removal costs.)

We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other generation, transmission and distribution assets. On January 1, 2003, we recorded a liability of \$219 million for our asset retirement obligations including the accretion impacts; a \$67 million increase in the carrying amount of the associated assets; and a net reduction of \$192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, we recorded a regulatory liability of \$40 million for our asset retirement obligations related to our regulated utility. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. We believe we can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation” (see Note 1) and SFAS No. 143 (see Note 12). Adopting SFAS No. 143 had no impact on our Consolidated Statements of Income or our Consolidated Statements of Cash Flow.

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 pending before the ACC is the key issue affecting our outlook. As discussed in greater detail in Note 3, in this rate case APS has requested, among other things, a 9.8% retail rate increase (approximately \$175 million annually), rate treatment for the PWEC Dedicated Assets and the recovery of \$234 million written off by APS as part of the 1999 Settlement Agreement. In its filed testimony, 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 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 hearing on the rate case is scheduled to begin on May 25, 2004. We believe the ACC will be able to make a decision by the end of 2004.

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 4.9% 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 year ended December 31, 2003 compared with the prior year period was 3.3%.

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 3 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 3 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 11 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. 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 2003 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. The annual earnings contribution from SunCor was \$56 million after tax in 2003. See Note 22 for further discussion. We anticipate SunCor's annual earnings contributions in 2004 and 2005 will be in the \$30 to \$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.

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 for El Dorado. In addition, we do not currently expect material losses related to NAC in the future.

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

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 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 a fixed-for-floating interest rate swap transaction (see Note 6 for additional information). The nuclear decommissioning fund also has risk associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

The table below presents 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, 2003. The interest rates presented in the tables below represent the weighted-average interest rates for the year ended December 31, 2003 (dollars in thousands):

December 31, 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	2.68%	\$ 1,209	5.33%	\$ 424,271
2005	—	—	1.99%	166,269	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	—	—	1.51%	386,860	5.83%	1,547,775
Total		<u>\$ 86,081</u>		<u>\$ 562,917</u>		<u>\$ 2,769,189</u>
Fair Value		<u>\$ 86,081</u>		<u>\$ 563,047</u>		<u>\$ 2,913,190</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 ERM, 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 2003 and 2002 (dollars in millions):

	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at December 31, 2002	\$ (49)	\$ 57
Change in mark-to-market losses for future period deliveries	(5)	(7)
Changes in cash flow hedges recorded in OCI	41	44
Ineffective portion of changes in fair value recorded in earnings	8	–
Mark-to-market losses/(gains) realized during the year	5	(25)
Mark-to-market of net positions at December 31, 2003	\$ –	\$ 69

	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at December 31, 2001	\$ (107)	\$ 138
Cumulative effect adjustment due to adoption of EITF 02-3	–	(109)
Change in mark-to-market (losses)/gains for future period deliveries	(13)	52
Changes in cash flow hedges recorded in OCI	57	16
Ineffective portion of changes in fair value recorded in earnings	11	–
Mark-to-market losses/(gains) realized during the year	3	(43)
Change in valuation techniques	–	3
Mark-to-market of net positions at December 31, 2002	\$ (49)	\$ 57

The tables below show the fair value of maturities of our non-trading and trading derivative contracts (dollars in millions) at December 31, 2003 by maturities and by the type of valuation that is performed to calculate the fair values. See Note 1, "Mark-to-Market Accounting," for more discussion on our valuation methods.

Regulated Electricity

Source of Fair Value	2004	2005	Years Thereafter	Total Fair Value
Prices actively quoted	\$ (4)	\$ 3	\$ –	\$ (1)
Prices provided by other external sources	2	–	–	2
Prices based on models and other valuation methods	(1)	–	–	(1)
Total by maturity	\$ (3)	\$ 3	\$ –	\$ –

Marketing and Trading

Source of Fair Value	2004	2005	2006	2007	2008	Years Thereafter	Total Fair Value
Prices actively quoted	\$ (18)	\$ –	\$ –	\$ 10	\$ 10	\$ –	\$ 2
Prices provided by other external sources	22	23	25	20	8	(2)	96
Prices based on models and other valuation methods	12	(7)	(13)	(14)	(6)	(1)	(29)
Total by maturity	\$ 16	\$ 16	\$ 12	\$ 16	\$ 12	\$ (3)	\$ 69

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

Commodity	Gain (Loss)	
	Price Up 10%	Price Down 10%
Mark-to-market changes reported in earnings (a):		
Electricity	\$ (2)	\$ 2
Natural gas	(1)	1
Other	1	–
Mark-to-market changes reported in OCI (b):		
Electricity	36	(36)
Natural gas	30	(30)
Total	\$ 64	\$ (63)

(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 non-payment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 37% of our \$237 million of risk management and trading assets as of December 31, 2003. See Note 1, “Mark-to-Market 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 “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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management at Pinnacle West has always understood and accepted responsibility for our financial statements and related disclosures and the effectiveness of internal control over financial reporting ("internal control"). Just as we do throughout all aspects of our business, we continuously strive to identify opportunities to enhance the effectiveness and efficiency of internal control.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act will require our 2004 Annual Report to contain a management's report and an independent accountants' report regarding the effectiveness of internal control. However, in this 2003 Annual Report, we chose to voluntarily include this report on internal control. As a basis for our report, we tested and evaluated the design, documentation and operating effectiveness of internal control.

In early March 2004, the PCAOB issued its auditing standard, which may require changes to the processes we utilize to test and evaluate the design, documentation and operating effectiveness of internal control and may affect our future internal control disclosures. Based on our assessment as of December 31, 2003, we make the following assertion:

- Management is responsible for establishing and maintaining effective internal control over financial reporting of Pinnacle West Capital Corporation and Subsidiaries (the "Company"). The internal control contains monitoring mechanisms, and actions are taken to correct deficiencies identified.

- There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.
- Management evaluated the Company's internal control over financial reporting as of December 31, 2003. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2003.

March 11, 2004