PINNACLE WEST CAPITAL CORPORATION

EVERY TIME
This Light Blinks

··· 2004 ANNUAL REPORT ···

Pinnacle West is a Phoenix-based company with consolidated assets of $9.9 billion and consolidated revenues of $2.9 billion. Through our subsidiaries, we generate, sell and deliver electricity and sell energy-related products and services to retail and wholesale customers in the western United States. We also develop residential, commercial and industrial real estate projects.

STRATEGIC OBJECTIVES

- Focus on superior long-term total returns for shareholders
- Provide Arizona electricity customers with reliable energy at fair prices
- Capture growth opportunities in our electricity markets
- Actively manage our costs and business risks
- Maximize the long-term value of our assets
- Increase our resource portfolio consistent with our native load, cash flow and market conditions
- Work with regulators to achieve positive regulatory outcomes that benefit both customers and shareholders
- Maintain a disciplined focus on our long-term goals while remaining agile

…we spend another $100 on electric infrastructure, because every six times this light blinks Arizona gains a new resident and every 32 times this light blinks a resident builds a new home.

That's the relentless pace of Arizona's growth – and it's our job to power it. It's a job we take very seriously, every minute of every day. As for this blinking light, we're told it will stop blinking in about 120 days. By contrast, our company will continue to keep the lights on for our customers. Just as we have for the last 118 years.

Note: The "blinking light messages" in this Annual Report are based on an eight-hour day, 365 days a year, and the light is set to blink every four seconds. For example, in 2005 our company will spend about $300 million to enhance Arizona's electric infrastructure and prepare for growth. This computes to roughly $822,000 per day, and using an eight-hour day, a little over $100 every four seconds.

FINANCIAL HIGHLIGHTS

dollars in thousands, except per share amounts

	Year Ended December 31,			Growth Rate	
	2004	2003	2002	2004 vs 2003	2003 vs 2002
INCOME HIGHLIGHTS					
Operating revenues	**$ 2,899,725**	$ 2,759,494	$ 2,405,250	5.1%	14.7 %
Income from continuing operations	**$ 235,218**	$ 225,803	$ 236,563	4.2%	(4.5)%
Net income	**$ 243,195**	$ 240,579	$ 149,408	1.1%	61.0 %
BALANCE SHEET HIGHLIGHTS					
Total assets – year-end	**$ 9,896,747**	$ 9,519,042	$ 9,139,157	4.0%	4.2 %
Common stock equity – year-end	**$ 2,950,196**	$ 2,829,779	$ 2,686,153	4.3%	5.3 %
PER SHARE HIGHLIGHTS					
Earnings per share from continuing operations – diluted	**$ 2.57**	$ 2.47	$ 2.78	4.0%	(11.2)%
Net income – diluted	**$ 2.66**	$ 2.63	$ 1.76	1.1%	49.4 %
Indicated annual dividend – year-end	**$ 1.90**	$ 1.80	$ 1.70	5.6%	5.9 %
Book value per share – year-end	**$ 32.14**	$ 30.97	$ 29.40	3.8%	5.3 %
STOCK PERFORMANCE					
Stock price per share – year-end	**$ 44.41**	$ 40.02	$ 34.09		
Stock price appreciation	**11.0%**	17.4%	(18.5)%		
Total return	**15.9%**	23.1%	(14.8)%		
Market capitalization – year-end	**$ 4,076,965**	$ 3,657,025	$ 3,115,142	11.5%	17.4 %

Every time this light blinks, APS installs two more feet of wire to serve the increasing needs of our customers.

THAT TRANSLATES TO ABOUT

5,000,000 feet of wire a year.

IN 2004, APS CONTINUED TO WORK HARD TO IMPROVE ARIZONA'S ELECTRIC INFRASTRUCTURE AND KEEP UP WITH ITS RAPID GROWTH BY ADDING MORE THAN 900 MILES OF TRANSMISSION AND DISTRIBUTION WIRES. IF LAID FROM END TO END, THE WIRE WOULD STRETCH FROM PHOENIX TO DENVER.

TO OUR SHAREHOLDERS

CHAIRMAN'S LETTER

We may not need a blinking light to tell you how fast we're growing, but it does make the point, doesn't it?

Now that I've got your attention, I'll admit the Arizona growth story is not news. But our *re-accelerating* growth is. Customer growth re-accelerated last year to 3.7 percent, back to our five-year average after a slight dip in 2002 and 2003. And our five-year average growth of 3.7 percent is three times the industry average.

That re-acceleration *is* news because growth will continue and even accelerate more this year. That story – and why growth is good for shareholders *and* customers – is the focus of this year's report to our owners.

Managing Growth in 2004

Reaching agreement on our rate case with customer groups and other stakeholders marked a high point in 2004, but it was only one among many. It was a demanding year for employees, who managed record growth, worked safer than ever, added another to a string of "top producing power station" years at the Palo Verde Nuclear Generating Station and calmly and professionally resolved a once-in-a-career transmission event.

Palo Verde's 10-year average capacity factor of 89.5 percent exceeded the 10-year national average by more than five percentage points. That means, just looking at APS' 29-percent share of Palo Verde, we averaged over 500,000 more megawatt-hours of production per year than we would have achieved with merely average performance. And Palo Verde's three-year-average production cost of 1.35 cents per kilowatt-hour was 27 percent below the national average for nuclear units. Higher capacity factors and lower costs add up to considerable savings for customers and a sizable contribution to earnings.

For our shareholders, the results in 2004 were strong. We set ourselves apart with our eleventh consecutive annual dividend increase. Shareholders received a total return (stock price increase plus dividends) of 16 percent. Our stock performance, even in the face of re-regulation, nearly matched the strong utility industry.

Our customers continued to enjoy high reliability, exceptional service and lower prices. From 1996 through 2004, APS invested about $3.6 billion to expand generation and upgrade transmission and distribution systems. Over this same period, the number of customer outages dropped by a third and the average interruption decreased in duration by 44 percent.

Those numbers illustrate our ability to manage growth *and* improve service. In a testament to the dedication to service shared throughout our company, our customer satisfaction ratings remained outstanding. APS ranked in the top 10 percent nationally – and first among investor-owned utilities in the West – in overall customer satisfaction in both the latest J.D. Power and Associates residential and business customer surveys.

In 2004, our customers experienced a full year of prices that were lower than 20 years ago, and 44 percent lower on an inflation-adjusted basis. After a decade of price decreases which ended in 2003, nominal prices are 16 percent lower than they were in 1993. To produce these kinds of numbers, we've been innovative in finding ways to cut costs and increase efficiencies. Year after year, with a series of price decreases over the last decade, we improved performance while keeping our regulatory commitments.

Growth means constant attention to resource planning. We grew into – and now we're outgrowing – the chunks of base-load generation and transmission capacity we've added over the years. The good news hidden in those engineering realities is that, with cooperation from our regulators, we can accommodate growth with upgraded facilities and a faster pace of technological innovation.

Leveraging Growth for Greater Reliability and Environmental Quality

Our customer growth is not just compatible with high reliability and environmental quality – it will ultimately enhance both. A high rate of growth brings opportunities that a stagnant or declining customer base would not allow – opportunities for achieving new efficiencies and employing new technologies.

Opportunities to replace older equipment come faster because of our growth. At every opportunity we're leveraging growth to improve reliability with new and better technology and infrastructure. Ultimately, the result is greater flexibility, cost efficiency and reliability. Growth-generated enhancements will propel us further and faster toward our goal of becoming a model 21st century utility.

Growth also has advantages for creating a sustainable environment. With the support of our regulators, we are pursuing growth of solar power – a technology in which we are a national leader among utilities – and of biomass, wind and hydrogen as future alternative sources of power.

We know the challenges of growth. We're vigilant, but not intimidated. We have a skilled and experienced group of men and women who tackle the opportunities. Our employees demand more of themselves today in order to meet the needs of tomorrow. That's the attitude guiding us toward continuing improvement.

Clashing Visions, Growing Agendas

As we said in last year's Annual Report, we're becoming a new kind of integrated utility. This year, with our new regulatory platform, we're much closer to our goal: a utility meeting its customers' needs reliably and efficiently with vertically integrated resources in an evolving market.

That vision is becoming more common as it's evident that competition and regulation – or re-regulation – will continue to clash and coexist. Clearly, our company will continue to live in both worlds. We're a vertically integrated company, and that means our generation resources as well as our "wires" infrastructure will primarily earn a regulated return. Yet we plan to obtain over 1,000 megawatts from the competitive market in the next three years. And with the high availability factors of our recently completed gas units, we will sell into the wholesale market. That sounds like competition.

The Federal Energy Regulatory Commission (FERC) and many states, including Arizona, will continue to adopt new and sometimes discordant positions. It's our job to satisfy both sets of rules and succeed in both worlds. In reality, market and regulatory structures will be determined by many factors – core competencies of the utility, market robustness and liquidity, and the interplay of power, policy and politics among state regulators, Congress and the FERC. Until there is more clarity, we will continue to balance these evolving structures, maintaining flexibility to exceed customer and shareholder expectations.

Turning Growth into Shareholder Value

We're confident in our ability to continue long-term improvement in earnings and cash flow. To attract the capital we need to keep up with growth, we must continue to compensate investors for shouldering risk. That's also the key that unlocks our ability to continue improving reliability while protecting our natural environment. We won't diminish our obligation to secure Arizona's energy future for our customers or concede our commitment to a fair return for shareholders.

WE HAVE AN ENVIABLE TRACK RECORD OF CONVERTING GROWTH INTO SHAREHOLDER VALUE, AND WE WILL CONTINUE THAT VALUE CREATION IN THE FUTURE.

Growth is good news for investors because it drives revenue growth that, well managed, produces earnings growth. We're confident we can continue to capture the benefits of growth for investors in the form of greater overall profitability, improved cash flow and higher dividends.

We have an enviable track record of converting growth into shareholder value, and we will continue that value creation in the future. Our strategy to secure the benefits of customer growth for investors is built around four major elements: achieving regulatory collaboration, controlling operating and capital costs through operational excellence and risk management, etching a strong financial profile and embracing technology and innovation.

First, we will continue to work with regulators to refine our newly restructured regulatory platform. After avoiding the structural failures of California-style deregulation, we expanded our approach to competition and regulation. We reached agreement last year with major customer groups on a new regulatory platform, the main elements of which were endorsed in early March by an administrative law judge. As this report goes to press, we are awaiting approval by our Arizona regulators.

The new platform will remedy our most urgent regulatory issues: it consolidates our company by putting the Arizona plants built by Pinnacle West Energy, our unregulated generation subsidiary, into the APS rate base. There, the plants will earn a regulated return and provide valuable, reliable, cost-effective and environmentally suitable capacity for our customers. It provides for a fuel and purchased power adjustment clause, our first since 1989, and includes a 4.2 percent rate increase.

Perhaps most important, this long overdue restructured regulatory platform will give us the opportunity to look forward not backward. Instead of re-doing the regulatory decisions of the late 90s, we can anticipate the infrastructure and service needs of our customers. We are responsible for meeting our customers' needs. We've done it before and we will continue to do so.

Second, we will manage power costs and capacity needs with excellent operations of a broad resource base and effective risk management strategies. With our low-cost nuclear and coal units fully deployed and achieving high capacity factors, we are well positioned to supply economical power for our customers. The new gas units at Redhawk, West Phoenix and Saguaro will enable a diverse energy supply mix of nuclear, coal and gas. As supplies tighten and spark spreads widen over the next few years, our gas units will allow us to capture opportunities in the wholesale market as well as supply our customers' needs.

We've controlled fuel and purchased power risk for years, and we will continue to do so. With a fuel adjustment clause added to our risk management tools, we will not reduce our intensity on minimizing cost. This fuel adjuster will become increasingly important as we achieve a more diverse generation fuel mix and as we contract for additional purchased power. Our new regulatory platform calls for a hiatus on building generation until 2015 – unless regulators agree the market is failing to provide adequate new capacity.

Third among our strategies for capturing the benefits of growth, we will achieve an improved financial profile. The new regulatory platform will provide some revenue boost. In addition, with the Arizona gas-fired units expected soon to be in the APS rate base, our corporate risk profile will be much lower, which will bolster our financial flexibility.

We've enhanced our cash flow over the last two years with asset sales, primarily by SunCor, our real estate subsidiary. As we've often said in the past about SunCor, we will maximize the value of our assets for shareholders over the long term with sales or purchases depending on opportunity and the economy. Years ago, we adopted a two-pronged financial strategy – maintaining an investment-grade rating on all corporate-level debt and targeting a steady pace of dividend increases. The former keeps our financing costs low – essential for a rapidly growing utility like APS – and the latter sets our financial profile apart from many other utilities.

Finally, innovation and further deployment of technology will help control our generation costs, but the potential for digital advances on the delivery side – the "wires" and customer service part – of our business is truly exciting. Technology will allow us to fully utilize our current assets and leverage our talented employee base. With computer software and digital intelligence facilitating and enhancing our operations, we will continue to provide better as well as more efficient customer service. In 1994, we served about

160 customers per employee. In 2004, we served 224 customers per employee while providing outstanding customer service, including more information, faster response to outages and higher reliability. Over the next decade, we expect to see equal or greater productivity gains and continuing service enhancements.

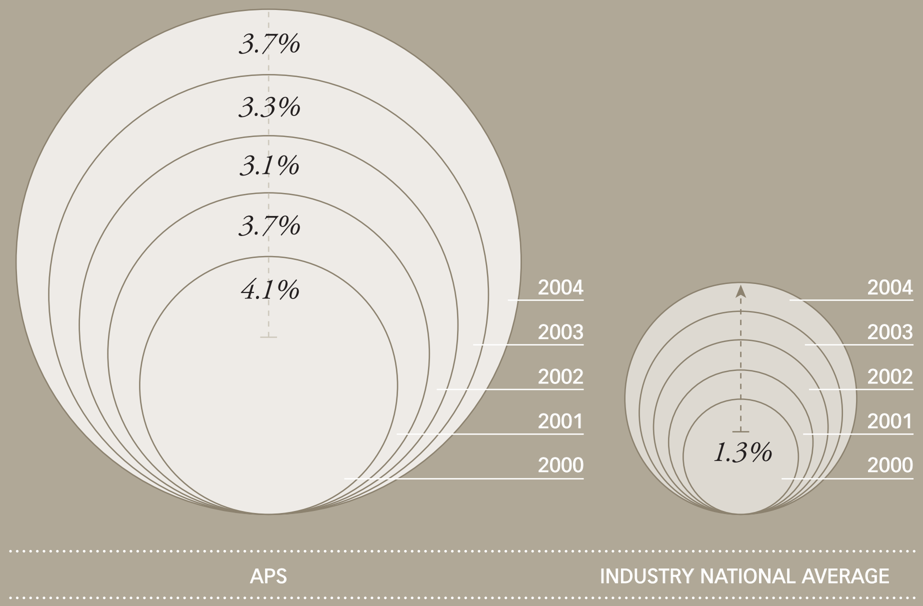
Over the long term, despite 10 years of regulatory uncertainty, market blowups in California and rate decreases in Arizona, we've generated a positive earnings and cash flow trend. With historic deregulation tremors behind us, we look forward to a more stable regulatory environment, a more robust wholesale power market, a better economy – and a resumption of earnings growth.

The past offers strong evidence of our ability to manage growth for the benefit of investors, but the earnings blip and dip from power marketing over the last few years may disguise the underlying stability of our core regulated utility business. Every year over the last 10 years, with the exception of the recession year 2001, our electricity sales growth exceeded both the Arizona population growth and our customer growth rates. The regulated core business gave us solid earnings and now it will drive future earnings growth.

What makes this all possible?

The answer is simple – our people. Each day, they come to the job ready to work hard, solve challenges and deliver unmatched service to our customers. They are the reasons we have succeeded for 118 years. They are the reasons we will continue to succeed in the future.

WILLIAM J. POST
Chairman



APS CUSTOMER GROWTH

Our accelerating customer growth continues at a pace three times the industry average.

Every time this light blinks, APS customers increase their peak energy demand by 130 watts.

THAT TRANSLATES TO ABOUT

350,000,000 watts a year.

IN 2005, THE PEAK ENERGY DEMAND OF OUR CUSTOMERS IS PROJECTED TO INCREASE 350 MILLION WATTS OVER 2004. THIS INCREASE REPRESENTS ENOUGH ENERGY TO SERVE THE EQUIVALENT OF 100,000 ARIZONA HOMES.

CREATING VALUE

Pinnacle West stock outperformed the S&P 500 Index again in 2004. Pinnacle West's total return for 2004 was 16 percent, compared to 10.8 percent for the S&P 500.

ACCOMPLISHMENTS

- We serve 225 customers for every employee, compared with fewer than 200 customers per employee in 1999 – a better than 11 percent efficiency increase.
- APS has significantly and steadily improved system reliability. In 1996, the average customer experienced 1.5 outages in a year. In 2004, that number decreased to about one outage – a 33 percent improvement.
- In both the latest J.D. Power Residential and Business Customer Satisfaction Surveys, APS earned the second highest ranking among utilities in the West in overall customer satisfaction, and ranked first among investor-owned utilities in the region.
- Improved efficiency and streamlined processes allowed APS to reduce customer electricity prices by about 16 percent since 1993.
- Sixteen APS line trucks and 40 crew members trekked across the country this summer to lend a much needed hand to overwhelmed Florida electric crews restoring power after the state's devastating hurricane season.

MANAGING GROWTH

APS' customer base grew 3.7 percent in 2004 – a rate three times the national average.

ACCOMPLISHMENTS

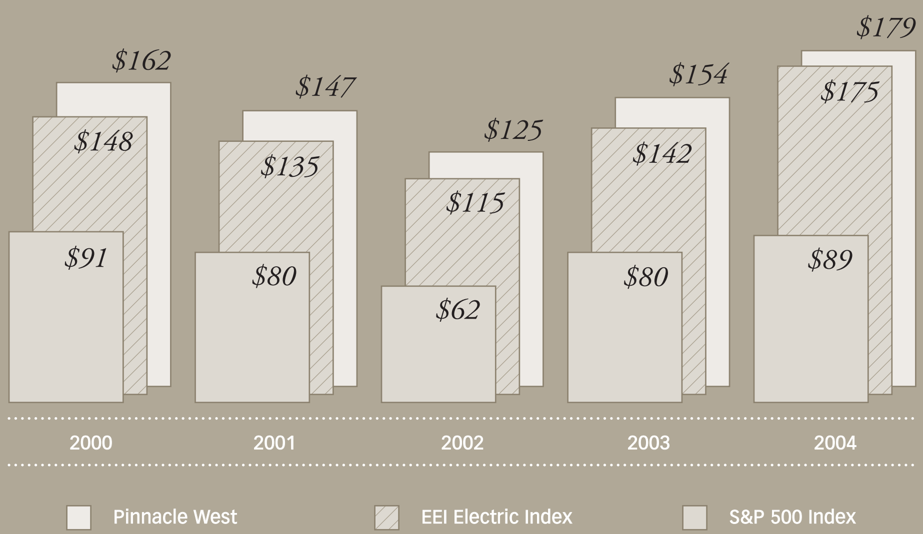
- In early 2005, APS surpassed one million customers for the first time in our company's 118-year history. This includes more than 300,000 customers added in the last decade alone.
- APS installed nearly 42,000 business and residential meters in 2004 – a new company record.
- To keep up with Arizona's growth, APS completed 75 substation improvement projects, five new substations and four new temporary substations in 2004.
- Our company continues to be a leader in renewable technology. In addition to expanding and developing more solar technology, we are exploring new renewable technologies including biogas, wind and biomass.
- Our call center fielded a record 4.5 million calls in 2004 and met its goal of answering calls in a timely manner.
- APS Energy Services has steadily grown its energy efficiency and district cooling and heating services in the Western region.

ACHIEVING EXCELLENCE

In 2004, the Palo Verde Nuclear Generating Station marked its 13th consecutive year as the nation's largest power producer of any kind.

ACCOMPLISHMENTS

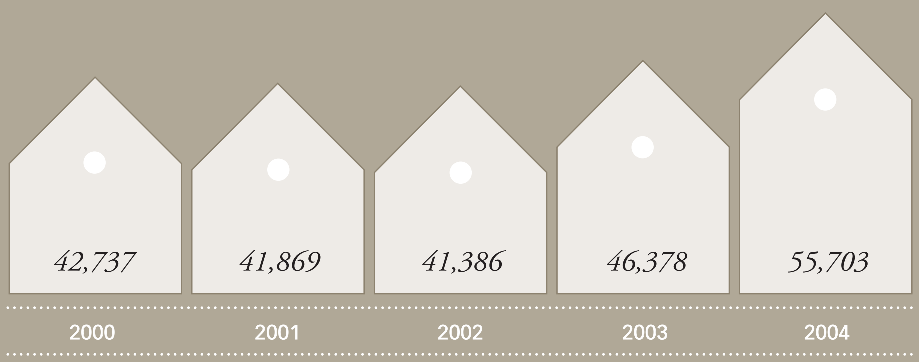
- In 2004, our company reduced our number of preventable recordable injuries, breaking the previous record low and setting a new safety performance standard.
- In the last 20 years, our West Phoenix, Ocotillo and Yucca Power Plants have zero combined lost-time accidents.
- SunCor, our real estate development company, produced significant earnings again this year – contributing $45 million to the bottom line.
- For the third time in as many studies, we earned the top rating – AAA – from Innovest Strategic Value Advisors, for our environmental performance.
- In 2004, Innovest Strategic Advisors also ranked Pinnacle West as the top utility in its Intangible Value Assessment (IVA). The IVA is designed to uncover investment value potential by measuring companies in areas such as corporate governance, community outreach, labor relations and regulatory relations.



Value of $100 invested on December 31, 1999, with dividends reinvested
(all dollar amounts as of year-end)

PINNACLE WEST STOCK PERFORMANCE COMPARISON

Pinnacle West stock has proven to be a sound investment, outpacing the S&P 500 Index and EEI Electric Index over the last five years.



PHOENIX AREA RESIDENTIAL BUILDING PERMITS

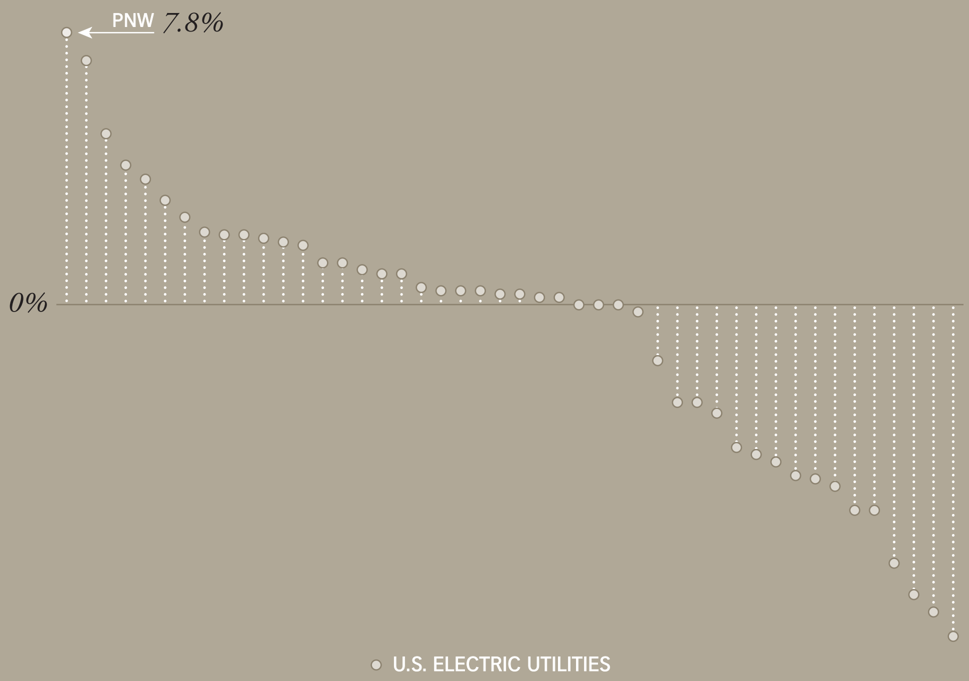
Phoenix – now the nation's fifth largest city – is experiencing rapid expansion in both population and new homes.

Every time this light blinks, another 45 square feet of a new home is built in the Phoenix area.

THAT TRANSLATES TO ABOUT

120,000,000 square feet a year.

IN 2004, THE PHOENIX AREA CONTINUED TO EXPAND, WITH ABOUT 120 MILLION SQUARE FEET OF NEW HOMES. THIS IS THE EQUIVALENT OF ADDING THE SQUARE FOOTAGE OF MORE THAN 50 EMPIRE STATE BUILDINGS EACH YEAR.



U.S. ELECTRIC UTILITIES AVERAGE
ANNUAL DIVIDEND GROWTH 1995 TO 2004

We've earned the top spot among all U.S. electric utilities in dividend growth over the last decade.

2004

CONSOLIDATED
Financial Information

SELECTED CONSOLIDATED FINANCIAL DATA *(dollars in thousands, except per share amounts)*

	2004	2003	2002	2001	2000
OPERATING RESULTS					
Operating revenues:					
Regulated electricity segment	**$ 2,035,247**	$ 1,978,075	$ 1,890,391	$ 1,984,305	$ 2,538,752
Marketing and trading segment	**461,870**	391,886	286,879	469,784	418,532
Real estate segment	**359,792**	361,604	201,081	168,908	158,365
Other revenues (a)	**42,816**	27,929	26,899	11,771	3,873
Total operating revenues	**$ 2,899,725**	$ 2,759,494	$ 2,405,250	$ 2,634,768	$ 3,119,522
Income from continuing operations	**235,218**	225,803	236,563	327,367	302,332
Discontinued operations – net of income taxes (b)	**7,977**	14,776	(21,410)	–	–
Cumulative effect of change in accounting – net of income taxes (c)(d)	**–**	–	(65,745)	(15,201)	–
Net income	**$ 243,195**	$ 240,579	$ 149,408	$ 312,166	$ 302,332
COMMON STOCK DATA					
Book value per share – year-end	**$ 32.14**	$ 30.97	$ 29.40	$ 29.46	$ 28.09
Earnings (loss) per weighted average common share outstanding:					
Continuing operations – basic	**$ 2.57**	$ 2.47	$ 2.79	$ 3.86	$ 3.57
Discontinued operations (b)	**0.09**	0.17	(0.26)	–	–
Cumulative effect of change in accounting (c)(d)	**–**	–	(0.77)	(0.18)	–
Net income – basic	**$ 2.66**	$ 2.64	$ 1.76	$ 3.68	$ 3.57
Continuing operations – diluted	**$ 2.57**	$ 2.47	$ 2.78	$ 3.85	$ 3.56
Net income – diluted	**$ 2.66**	$ 2.63	$ 1.76	$ 3.68	$ 3.56
Dividends declared per share	**$ 1.825**	$ 1.725	$ 1.625	$ 1.525	$ 1.425
Indicated annual dividend rate per share – year end	**$ 1.90**	$ 1.80	$ 1.70	$ 1.60	$ 1.50
Weighted-average common shares outstanding – basic	**91,396,904**	91,264,696	84,902,946	84,717,649	84,732,544
Weighted-average common shares outstanding – diluted	**91,532,473**	91,405,134	84,963,921	84,930,140	84,935,282
BALANCE SHEET DATA					
Total assets	**$ 9,896,747**	$ 9,519,042	$ 9,139,157	$ 8,529,124	$ 7,697,558
Liabilities and equity:					
Long-term debt less current maturities	**$ 2,584,985**	$ 2,616,585	$ 2,743,741	$ 2,673,078	$ 1,955,083
Other liabilities	**4,361,566**	4,072,678	3,709,263	3,356,723	3,359,761
Total liabilities	**6,946,551**	6,689,263	6,453,004	6,029,801	5,314,844
Common stock equity	**2,950,196**	2,829,779	2,686,153	2,499,323	2,382,714
Total liabilities and equity	**$ 9,896,747**	$ 9,519,042	$ 9,139,157	$ 8,529,124	$ 7,697,558

(a) Includes reclassifications of revenues in 2003 and 2002 related to the discontinued operations of NAC. See Note 22 of Notes to Pinnacle West's Consolidated Financial Statements.

(b) NAC and real estate discontinued operations. See Note 22 of Notes to Pinnacle West's Consolidated Financial Statements.

(c) Change in accounting standards related to energy trading activities in 2002. See Note 18 of Notes to Pinnacle West's Consolidated Financial Statements.

(d) Change in accounting standards related to derivatives in 2001.

QUARTERLY STOCK PRICES AND DIVIDENDS PAID PER SHARE *Stock Symbol:* PNW

2004	High	Low	Close	Dividends Per Share
1st Quarter	**$ 40.81**	**$ 36.90**	**$ 39.35**	**$ 0.450**
2nd Quarter	**41.50**	**36.30**	**40.39**	**0.450**
3rd Quarter	**42.99**	**39.63**	**41.50**	**0.450**
4th Quarter	**45.84**	**41.61**	**44.41**	**0.475**

2003	High	Low	Close	Dividends Per Share
1st Quarter	$ 37.13	$ 28.34	$ 33.24	$ 0.425
2nd Quarter	39.59	31.35	37.45	0.425
3rd Quarter	38.03	32.87	35.50	0.425
4th Quarter	40.48	34.91	40.02	0.450

GLOSSARY

ACC – Arizona Corporation Commission
ADEQ – Arizona Department of Environmental Quality
AFUDC – allowance for funds used during construction
ALJ – Administrative Law Judge
APS – Arizona Public Service Company, a subsidiary of the Company
APS ENERGY SERVICES – APS Energy Services Company, Inc., a subsidiary of the Company
CC&N – Certificate of Convenience and Necessity
CHOLLA – Cholla Power Plant
CLEAN AIR ACT – Clean Air Act, as amended
COMPANY – Pinnacle West Capital Corporation
DOE – United States Department of Energy
EITF – FASB's Emerging Issues Task Force
EL DORADO – El Dorado Investment Company, a subsidiary of the Company
EPA – United States Environmental Protection Agency
ERMC – Energy Risk Management Committee
FASB – Financial Accounting Standards Board
FERC – United States Federal Energy Regulatory Commission
FIN – FASB Interpretation
FINANCING ORDER – ACC Order that authorized APS' $500 million loan to Pinnacle West Energy in May 2003
FOUR CORNERS – Four Corners Power Plant
FSP – FASB Staff Position
GAAP – accounting principles generally accepted in the United States of America
IRS – United States Internal Revenue Service
ISO – California Independent System Operator
KWH – kilowatt-hour, one thousand watts per hour
MOODY'S – Moody's Investors Service
MW – megawatt, one million watts
MWH – megawatt-hours, one million watts per hour
NAC – collectively, NAC Holding Inc. and NAC International Inc., subsidiaries of El Dorado that were sold in November 2004
NATIVE LOAD – retail and wholesale sales supplied under traditional cost-based rate regulation
1999 SETTLEMENT AGREEMENT – comprehensive settlement agreement related to the implementation of retail electric competition
NRC – United States Nuclear Regulatory Commission
NUCLEAR WASTE ACT – Nuclear Waste Policy Act of 1982, as amended
OCI – other comprehensive income
PALO VERDE – Palo Verde Nuclear Generating Station, also known as ANPP
PINNACLE WEST – Pinnacle West Capital Corporation, the Company
PINNACLE WEST ENERGY – Pinnacle West Energy Corporation, a subsidiary of the Company
PPL SUNDANCE – PPL Sundance Energy, LLC
PSA – power supply adjuster
PWEC DEDICATED ASSETS – the following Pinnacle West Energy power plants, each of which is dedicated to serving APS' customers: Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3
PX – California Power Exchange
RFP – request for proposals
RULES – ACC retail electric competition rules
SALT RIVER PROJECT – Salt River Project Agricultural Improvement and Power District
SEC – United States Securities and Exchange Commission
SFAS – Statement of Financial Accounting Standards
SNWA – Southern Nevada Water Authority
SPARK SPREAD – excess of market power price over market gas price at a specific location
SPE – special-purpose entity
STANDARD & POOR'S – Standard & Poor's Corporation
SUNCOR – SunCor Development Company, a subsidiary of the Company
SUNDANCE PLANT – PPL Sundance's 450-megawatt generating facility located approximately 55 miles southeast of Phoenix, Arizona
T&D – transmission and distribution
TRACK A ORDER – ACC order dated September 10, 2002 regarding generation asset transfers and related issues
TRACK B ORDER – ACC order dated March 14, 2003 regarding competitive solicitation requirements for power purchases by Arizona's investor-owned electric utilities
TRADING – energy-related activities entered into with the objective of generating profits on changes in market prices
2004 SETTLEMENT AGREEMENT – an agreement proposing terms under which APS' general rate case would be settled
VIE – variable interest entity

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	**$ 243**	$ 241	$ 149

(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	7	4
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	33	20
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	$ 36	9
Discontinued operations (primarily real estate segment, see Note 22)		(7)
Net increase in net income		$ 2

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	(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 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	$ (60)	(11)
Discontinued operations (primarily NAC, see Note 22)		37
Increase due to 2002 cumulative effect of a change in accounting for trading activities		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.

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

(a) 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.

(b) 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.

(c) Primarily information systems and facilities projects.

(d) 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):

	Increase/(Decrease)		
Actuarial Assumption (a)	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):

	Increase/(Decrease)	
Actuarial Assumption (a)	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		$ 86,081		$ 561,317		$ 2,769,083
Fair value		$ 86,081		$ 561,447		$ 2,913,085

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		**$ 565,860**		**$ 2,160,449**
Fair value		**$ 565,799**		**$ 2,254,061**

	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		$ 386,860		$ 2,244,444
Fair value		$ 386,906		$ 2,365,821

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 manage-ment 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	**$ 34**	**$ 107**	$ –	$ 69

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

	2005	2006	2007	Total Fair Value
Source of 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	**$ 26**	**$ 10**	**$ (2)**	**$ 34**

Marketing and Trading

	2005	2006	2007	2008	2009	Years Thereafter	Total Fair Value
Source of 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	**$ 36**	**$ 26**	**$ 29**	**$ 18**	**$ (1)**	**$ (1)**	**$ 107**

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 Gain (Loss)		December 31, 2003 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	**$ 77**	**$ (77)**	$ 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 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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13(a) - 15(f). Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control – Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2004. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and relates also to the Company's consolidated financial statements.

March 15, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Pinnacle West Capital Corporation
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2004. We also have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on these financial statements, an opinion on management's assessment, and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM *(continued)*

accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 18 to the consolidated financial statements, in 2002 the Company changed its method for accounting for trading activities in order to comply with the provisions of Emerging Issues Task Force Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.*

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona
March 15, 2005

CONSOLIDATED STATEMENTS OF INCOME *(dollars and shares in thousands, except per share amounts)*

	Year Ended December 31,		
	2004	2003	2002
OPERATING REVENUES			
Regulated electricity segment	**$ 2,035,247**	$ 1,978,075	$ 1,890,391
Marketing and trading segment	**461,870**	391,886	286,879
Real estate segment	**359,792**	361,604	201,081
Other revenues	**42,816**	27,929	26,899
Total	**2,899,725**	2,759,494	2,405,250
OPERATING EXPENSES			
Regulated electricity segment purchased power and fuel	**567,433**	517,320	376,911
Marketing and trading segment purchased power and fuel	**382,147**	344,862	154,987
Operations and maintenance	**596,557**	548,732	584,538
Real estate operations segment	**289,900**	305,974	185,925
Depreciation and amortization	**401,105**	435,140	422,299
Taxes other than income taxes	**122,216**	110,270	107,952
Other expenses	**34,108**	23,254	21,895
Total	**2,393,466**	2,285,552	1,854,507
OPERATING INCOME	**506,259**	473,942	550,743
OTHER			
Allowance for equity funds used during construction	**4,885**	14,240	–
Other income (Note 19)	**53,989**	35,563	14,910
Other expenses (Note 19)	**(21,510)**	(20,574)	(33,655)
Total	**37,364**	29,229	(18,745)
INTEREST EXPENSE			
Interest charges	**195,859**	204,339	187,039
Capitalized interest	**(16,311)**	(29,444)	(43,749)
Total	**179,548**	174,895	143,290
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**364,075**	328,276	388,708
INCOME TAXES	**128,857**	102,473	152,145
INCOME FROM CONTINUING OPERATIONS	**235,218**	225,803	236,563
Income (loss) from discontinued operations – net of income tax expense (benefit) of $5,480, $9,616 and ($14,045)	**7,977**	14,776	(21,410)
Cumulative effect of a change in accounting for trading activities – net of income tax benefit of ($43,123)	**–**	–	(65,745)
NET INCOME	**$ 243,195**	$ 240,579	$ 149,408
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – BASIC	**91,397**	91,265	84,903
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – DILUTED	**91,532**	91,405	84,964
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Income from continuing operations – basic	**$ 2.57**	$ 2.47	$ 2.79
Net income – basic	**2.66**	2.64	1.76
Income from continuing operations – diluted	**2.57**	2.47	2.78
Net income – diluted	**2.66**	2.63	1.76
DIVIDENDS DECLARED PER SHARE	**$ 1.825**	$ 1.725	$ 1.625

See Notes to Pinnacle West's Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS *(dollars in thousands)*

	December 31, 2004	December 31, 2003
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 163,366**	$ 131,062
Investment in debt securities	**181,175**	91,850
Customer and other receivables	**367,863**	354,666
Allowance for doubtful accounts	**(4,896)**	(9,223)
Accrued utility revenues	**93,227**	88,629
Materials and supplies (at average cost)	**101,333**	96,099
Fossil fuel (at average cost)	**20,512**	28,367
Assets from risk management and trading activities (Note 18)	**166,896**	97,630
Assets related to discontinued operations (Note 22)	**–**	23,065
Other current assets	**47,654**	72,649
Total current assets	**1,137,130**	974,794
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Notes 1 and 6)	**382,398**	358,441
Assets from risk management and trading activities – long-term (Note 18)	**224,341**	138,946
Decommissioning trust accounts (Note 12)	**267,700**	240,645
Other assets	**107,212**	88,473
Total investments and other assets	**981,651**	826,505
PROPERTY, PLANT AND EQUIPMENT (NOTES 1, 6, 9 AND 10)		
Plant in service and held for future use	**10,486,648**	9,904,874
Less accumulated depreciation and amortization	**3,365,954**	3,145,609
Total	**7,120,694**	6,759,265
Construction work in progress	**258,119**	554,876
Intangible assets, net of accumulated amortization of $158,584 and $128,126	**105,486**	108,534
Nuclear fuel, net of accumulated amortization of $59,020 and $58,053	**51,188**	52,011
Net property, plant and equipment	**7,535,487**	7,474,686
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	**135,051**	132,349
Other deferred debits	**107,428**	110,708
Total deferred debits	**242,479**	243,057
TOTAL ASSETS	**$ 9,896,747**	$ 9,519,042

See Notes to Pinnacle West's Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS *(dollars in thousands)*

	December 31, 2004	December 31, 2003
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	**$ 373,526**	$ 283,021
Accrued taxes	**245,611**	69,769
Accrued interest	**38,795**	51,825
Short-term borrowings (Note 5)	**71,030**	86,081
Current maturities of long-term debt (Note 6)	**617,165**	704,914
Customer deposits	**55,558**	49,783
Deferred income taxes (Note 4)	**9,057**	631
Liabilities from risk management and trading activities (Note 18)	**113,406**	92,755
Liabilities related to discontinued operations (Note 22)	**–**	16,427
Other current liabilities	**101,748**	77,362
Total current liabilities	**1,625,896**	1,432,568
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	**2,584,985**	2,616,585
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	**1,227,553**	1,338,527
Regulatory liabilities (Notes 1, 3 and 4)	**506,646**	468,694
Liability for asset retirements (Note 12)	**251,612**	234,440
Pension liability (Note 8)	**234,445**	188,041
Liabilities from risk management and trading activities – long-term (Note 18)	**156,262**	82,730
Unamortized gain – sale of utility plant (Note 9)	**50,333**	54,909
Other	**308,819**	272,769
Total deferred credits and other	**2,735,670**	2,640,110
COMMITMENTS AND CONTINGENCIES (NOTES 3, 11 AND 12)		
COMMON STOCK EQUITY (NOTE 7)		
Common stock, no par value; authorized 150,000,000 shares; issued 91,802,861 at end of 2004 and 91,379,947 at end of 2003	**1,769,047**	1,744,354
Treasury stock at cost; 9,522 shares at end of 2004 and 92,015 shares at end of 2003	**(428)**	(3,273)
Total common stock	**1,768,619**	1,741,081
Accumulated other comprehensive income (loss):		
Minimum pension liability adjustment	**(81,788)**	(66,564)
Derivative instruments	**59,243**	27,563
Total accumulated other comprehensive loss	**(22,545)**	(39,001)
Retained earnings	**1,204,122**	1,127,699
Total common stock equity	**2,950,196**	2,829,779
TOTAL LIABILITIES AND EQUITY	**$ 9,896,747**	$ 9,519,042

See Notes to Pinnacle West's Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS *(dollars in thousands)*

	Year Ended December 31, 2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 243,195**	$ 240,579	$ 149,408
Adjustment to reconcile net income to net cash provided by operating activities:			
Loss (income) from discontinued operations, net of tax	**(7,977)**	(14,776)	21,410
Cumulative effect of accounting change, net of tax	**–**	–	65,745
Equity earnings in Phoenix Suns partnership	**(34,594)**	–	–
Depreciation and amortization	**401,105**	435,140	422,299
Nuclear fuel amortization	**30,446**	28,757	31,185
Allowance for equity funds used during construction	**(4,885)**	(14,240)	–
Deferred income taxes	**(113,850)**	81,756	191,135
Change in mark-to-market valuations	**(18,915)**	17,410	(18,146)
Redhawk Units 3 and 4 cancellation charge	**–**	–	49,192
Changes in current assets and liabilities:			
Customer and other receivables	**(17,524)**	(12,456)	60,336
Accrued utility revenues	**(4,598)**	5,875	(18,373)
Materials, supplies and fossil fuel	**2,621**	(4,629)	(11,599)
Other current assets	**24,995**	(6,865)	(6,643)
Accounts payable	**98,001**	(7,125)	17,008
Accrued taxes	**175,842**	(1,338)	(36,041)
Accrued interest	**(13,030)**	(1,193)	4,212
Other current liabilities	**33,669**	8,668	24,755
Proceeds from the sale of real estate assets	**80,035**	130,597	47,906
Real estate investments	**(62,812)**	(51,837)	(56,355)
Increase in regulatory assets	**(2,702)**	(20,971)	(11,029)
Change in risk management and trading – assets	**(2,549)**	46,911	(11,700)
Change in risk management and trading – liabilities	**13,018**	(11,613)	(22,783)
Change in customer advances	**6,402**	7,270	(23,780)
Change in pension liability	**23,822**	19,074	(3,009)
Change in other long-term assets	**(39,710)**	13,124	(13,593)
Change in other long-term liabilities	**32,075**	12,635	9,785
Net cash flow provided by operating activities	**842,080**	900,753	861,325
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(538,232)**	(713,256)	(909,259)
Proceeds from sale of Silverhawk	**90,967**	–	–
Capitalized interest	**(16,311)**	(29,444)	(43,749)
Discontinued operations – Real Estate	**8,927**	27,193	28,917
Discontinued operations – NAC	**8,499**	(19,971)	(12,259)
Proceeds from the sale of the Phoenix Suns partnership	**23,101**	–	–
Purchases of investment securities	**(1,040,955)**	(877,660)	–
Proceeds from sale of investment securities	**951,630**	785,810	–
Proceeds from commercial real estate properties	**–**	33,297	9,272
Other	**(19,579)**	(21,040)	36,635
Net cash flow used for investing activities	**(531,953)**	(815,071)	(890,443)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	**478,328**	656,850	674,919
Short-term borrowings and payments – net	**(15,051)**	(173,303)	(306,079)
Dividends paid on common stock	**(166,772)**	(157,417)	(137,721)
Repayment of long-term debt	**(604,015)**	(366,497)	(354,916)
Common stock equity issuance	**18,291**	–	199,238
Other	**11,396**	8,181	2,624
Net cash flow (used for) provided by financing activities	**(277,823)**	(32,186)	78,065
NET INCREASE IN CASH AND CASH EQUIVALENTS	**32,304**	53,496	48,947
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**131,062**	77,566	28,619
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$ 163,366**	$ 131,062	$ 77,566
Supplemental disclosure of cash flow information			
Cash paid during the period for:			
Income taxes paid/(refunded)	**$ 66,447**	$ 32,816	$ (17,918)
Interest paid, net of amounts capitalized	**$ 191,865**	$ 161,581	$ 126,322

See Notes to Pinnacle West's Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY *(dollars in thousands)*

	Year Ended December 31,		
	2004	2003	2002
COMMON STOCK (NOTE 7)			
Balance at beginning of year	**$ 1,744,354**	$ 1,737,258	$ 1,536,924
Issuance of common stock	**18,291**	–	199,238
Other	**6,402**	7,096	1,096
Balance at end of year	**1,769,047**	1,744,354	1,737,258
TREASURY STOCK (NOTE 7)			
Balance at beginning of year	**(3,273)**	(4,358)	(5,886)
Purchase of treasury stock	**(2,986)**	–	(5,971)
Reissuance of treasury stock used for stock compensation, net	**5,831**	1,085	7,499
Balance at end of year	**(428)**	(3,273)	(4,358)
RETAINED EARNINGS			
Balance at beginning of year	**1,127,699**	1,044,537	1,032,850
Net income	**243,195**	240,579	149,408
Common stock dividends	**(166,772)**	(157,417)	(137,721)
Balance at end of year	**1,204,122**	1,127,699	1,044,537
ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)			
Balance at beginning of year	**(39,001)**	(91,284)	(64,565)
Minimum pension liability adjustment, net of tax expense (benefit) of ($9,756), $3,700 and ($46,109)	**(15,224)**	4,700	(70,298)
Unrealized gain on derivative instruments, net of tax expense of $31,117, $33,298 and $28,820	**48,226**	51,089	43,939
Reclassification of realized gain to income, net of tax benefit of ($10,695), ($2,343) and ($237)	**(16,546)**	(3,506)	(360)
Balance at end of year	**(22,545)**	(39,001)	(91,284)
TOTAL COMMON STOCK EQUITY	**$ 2,950,196**	$ 2,829,779	$ 2,686,153
COMPREHENSIVE INCOME (LOSS)			
Net income	**$ 243,195**	$ 240,579	$ 149,408
Other comprehensive income (loss)	**16,456**	52,283	(26,719)
Comprehensive income	**$ 259,651**	$ 292,862	$ 122,689

See Notes to Pinnacle West's Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

Pinnacle West's Consolidated Financial Statements include the accounts of Pinnacle West and our subsidiaries: APS, Pinnacle West Energy, APS Energy Services, SunCor and El Dorado (principally NAC). See Note 22 for a discussion of the sale of NAC in November 2004. Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

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 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. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we conduct our unregulated generation operations. APS Energy Services was formed in 1998 and provides competitive commodity energy and energy-related products to key customers in competitive markets in the western United States. SunCor is a developer of residential, commercial and industrial real estate projects in Arizona, New Mexico, Idaho and Utah. El Dorado is an investment firm.

Accounting Records and Use of Estimates

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

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances and in interest rates. We manage risks associated with these market fluctuations by utilizing various instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

We account for our derivative contracts in accordance with SFAS No. 133, as amended by SFAS No. 149, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative instruments are either recognized periodically in income or, if certain hedge criteria are met, in common stock equity (as a component of other comprehensive income (loss)). SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard.

Prior to the fourth quarter of 2002, we accounted for our trading activity at fair value, with changes in fair value reported in earnings as required by EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." In the fourth quarter of 2002, we adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," which rescinded EITF 98-10. 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, as amended. Energy trading 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.

Under fair value (mark-to-market) accounting, derivative contracts for the purchase or sale of energy commodities are reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as current or long-term assets and liabilities from risk management and trading activities on the Consolidated Balance Sheets.

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

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

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

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

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

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our marketing and trading portfolio includes structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. Our practice is to hedge within timeframes established by the ERMC.

See Note 18 for additional information about our derivative and energy trading accounting policies.

Regulatory Accounting

APS is regulated by the ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers.

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

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

The detail of regulatory assets is as follows (dollars in millions):

	December 31,	
	2004	2003
Electric industry restructuring transition costs (Note 3)	**$ 50**	$ 46
Deferred compensation	**24**	24
Loss on reacquired debt (a)	**17**	12
Capital contributions on the Mead-Phoenix transmission line	**13**	11
Regulatory asset for deferred income taxes	**12**	9
Spent nuclear fuel storage (Note 11)	**11**	7
Balance recoverable under the 1999 Settlement Agreement	**–**	18
Other	**8**	5
Total regulatory assets	**$ 135**	$ 132

(a) See "Reacquired Debt Costs" below.

The detail of regulatory liabilities is as follows (dollars in millions):

	December 31,	
	2004	2003
Removal costs (a)	**$ 462**	$ 439
Deferred gains on utility property	**20**	20
Deferred interest income (b)	**22**	8
Other	**3**	2
Total regulatory liabilities	**$ 507**	$ 469

(a) See Note 12 for information on Asset Retirement Obligations.
(b) See "ACC Financing Orders" in Note 3 for information on the "APS Loan".

Utility Plant and Depreciation

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

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

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Prior to 2003, we charged removal costs, less salvage, to accumulated depreciation. Effective January 1, 2003, we applied the provisions of SFAS No. 143. The standard requires that liabilities associated with the retirement of tangible long-lived assets be recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 12.

APS records a regulatory liability for the asset retirement obligations related to its regulated assets. This regulatory liability represents the difference between the amount that has been recovered in regulated rates and the amount calculated under SFAS No. 143. APS believes it can recover in regulated rates the transition and ongoing current period costs calculated in accordance with SFAS No. 143.

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2004 were as follows:

- Fossil plant – 23 years;
- Nuclear plant – 18 years;
- Other generation – 26 years;
- Transmission – 36 years;
- Distribution – 23 years; and
- Other – 8 years.

For the years 2002 through 2004, the depreciation rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 12.5%. The weighted-average rate was 3.36% for 2004, 3.35% for 2003 and 3.35% for 2002. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 55 years.

Investments

El Dorado accounts for its investments using the equity (if significant influence) and cost (less than 20% ownership) methods. See Note 22 for a discussion of the sale of NAC.

The Company's investments have been reviewed in accordance with EITF 03-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments," and no other-than-temporary impairments were identified.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance non-regulated construction projects. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. The rate used to calculate capitalized interest was a composite rate of 4.44% for 2004, 4.55% for 2003 and 4.80% for 2002. Capitalized interest ceases to accrue when construction is complete.

Allowance for Funds Used During Construction

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction of regulated utility plant. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 8.42% for 2004 and 8.55% for 2003. APS compounds AFUDC monthly and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

In 2003, APS returned to the AFUDC method of capitalizing interest and equity costs associated with construction projects in a regulated utility. This is consistent with APS returning to a vertically-integrated utility, as evidenced by APS' 2003 general rate case filing, which includes the request for rate recognition of generation assets. Prior to 2003, APS capitalized interest in accordance with SFAS No. 34, "Capitalization of Interest Cost." Although AFUDC both increases the plant balance and results in higher current earnings during the construction period, AFUDC is realized in future revenues through depreciation provisions included in rates. This change increased earnings by $11 million in 2003 as compared to what it would have been under SFAS No. 34.

Electric Revenues

We derive electric revenues from sales of electricity to our regulated Native Load customers and sales to other parties from our marketing and trading activities. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. However, the determination and billing of electricity sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers since the date of the last meter reading and billing and the corresponding unbilled revenue are estimated. We exclude sales taxes on electric revenues from both revenue and taxes other than income taxes.

Revenues from our Native Load customers and non-derivative instruments are reported on a gross basis on Pinnacle West's Consolidated Statements of Income. 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 net these book-outs, which reduces both revenues and purchased power and fuel costs.

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

Real Estate Revenues

SunCor recognizes revenue from land, home and qualifying commercial operating assets sales in full, provided (a) the income is determinable, that is, the collectibility of the sales price is reasonably assured or the amount that will not be collectible can be estimated, and (b) the earnings process is virtually complete, that is, SunCor is not obligated to perform significant activities after the sale to earn the income. Unless both conditions exist, recognition of all or part of the income is postponed under the percentage of completion method per SFAS No. 66 “Accounting for Sales of Real Estate.” SunCor recognizes income only after the assets’ title has passed. A single method of recognizing income is applied to all sales transactions within an entire home, land or commercial development project. Commercial property and management revenues are recorded over the term of the lease or period in which services are provided. In addition, see Note 22 – Discontinued Operations.

Real Estate Investments

Real estate investments primarily include SunCor’s land, home inventory and investments in joint ventures. Land includes acquisition costs, infrastructure costs, property taxes and capitalized interest directly associated with the acquisition and development of each project. Land under development and land held for future development are stated at accumulated cost, except that, to the extent that such land is believed to be impaired, it is written down to fair value. Land held for sale is stated at the lower of accumulated cost or estimated fair value less costs to sell. Home inventory consists of construction costs, improved lot costs, capitalized interest and property taxes on homes under construction. Home inventory is stated at the lower of accumulated cost or estimated fair value less costs to sell. Investments in joint ventures for which SunCor does not have a controlling financial interest are not consolidated but are accounted for using the equity method of accounting. In 2003, SunCor acquired two joint ventures for $10 million and consolidated $53 million of assets and $43 million of liabilities, which are included on the Consolidated Balance Sheets at December 31, 2003. The $10 million cash investment is included on the other investing line of the Consolidated Statements of Cash Flow at December 31, 2003. In addition, see Note 22 – Discontinued Operations.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an initial maturity of three months or less to be cash equivalents.

We have investments in auction rate securities in which interest rates are reset on a short-term basis; however, the underlying contract maturity dates extend beyond three months. We classify the investments in auction rate securities as investments in debt securities on our Consolidated Balance Sheets. We have reclassified cash at December 31, 2003 of $92 million to investment in debt securities. Included in that reclassification is $70 million related to APS. The purchase and sale activities related to these investments have also been reclassified on the Consolidated Statement of Cash Flows.

Nuclear Fuel

APS charges nuclear fuel to fuel expense by using the unit-of-production method. The unit-of-production method is an amortization method based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation. See Note 11 for information about spent nuclear fuel disposal and Note 12 for information on nuclear decommissioning costs.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by SFAS No. 109, "Accounting for Income Taxes." We file our federal income tax return on a consolidated basis and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each subsidiary as though each subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. See Note 4.

Reacquired Debt Costs

For reacquired debt costs related to the regulated portion of APS' business, APS defers those gains and losses incurred upon early retirement and is seeking recovery of the net amount of losses in the APS general rate case (see Note 3).

Stock-Based Compensation

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

The following chart compares our net income, stock compensation expense and earnings per share to what those items would have been if we had recorded stock compensation expense based on the fair value method for all stock grants through 2004 (dollars in thousands, except per share amounts):

	Year Ended December 31,		
	2004	2003	2002
Net Income as reported:	**$ 243,195**	$ 240,579	$ 149,408
Add: Stock compensation expense included in reported net income (net of tax)	**4,690**	3,514	2,347
Deduct: Total stock compensation expense determined under fair value method (net of tax)	**(5,311)**	(5,220)	(3,742)
Pro forma net income	**$ 242,574**	$ 238,873	$ 148,013
Earnings per share – basic:			
As reported	**$ 2.66**	$ 2.64	$ 1.76
Pro forma (fair value method)	**$ 2.65**	$ 2.62	$ 1.74
Earnings per share – diluted:			
As reported	**$ 2.66**	$ 2.63	$ 1.76
Pro forma (fair value method)	**$ 2.65**	$ 2.61	$ 1.74

In order to calculate the fair value of the 2004, 2003 and 2002 stock option grants and the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

	2004	2003	2002
Risk-free interest rate	**3.15%**	3.35%	4.17%
Dividend yield	**4.76%**	5.26%	4.17%
Volatility	**17.04%**	38.03%	22.59%
Expected life (months)	**60**	60	60

See Note 16 for further discussion about our stock compensation plans.

Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets on Pinnacle West's Consolidated Balance Sheets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." The intangible assets are amortized over their finite useful lives. Amortization expense was $34 million in 2004, $25 million in 2003, and $21 million in 2002. Estimated amortization expense on existing intangible assets over the next five years is $33 million in 2005, $31 million in 2006, $25 million in 2007, $16 million in 2008, and $1 million in 2009. At December 31, 2004, the weighted average amortization period for intangible assets is 7 years.

2. NEW ACCOUNTING STANDARDS

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment." The standard establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS No. 123R is effective as of the beginning of the first interim or annual period that begins after June 15, 2005. We are currently accounting for stock-based compensation using the fair value method and are evaluating the impacts of this new guidance, but we do not believe it will have a material impact on our financial statements.

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

- Note 8 for FSP 106-2 regarding the Medicare Prescription Drug, Improvement and Modernization Act related to retirement plans and other benefits;
- Note 18 for EITF 02-3 and DIG Issue No. C15 related to accounting for derivatives and energy contracts; and
- Note 20 for FIN No. 46R related to variable interest entities.

3. REGULATORY MATTERS

Electric Industry Restructuring

State

APS GENERAL RATE CASE; 2004 SETTLEMENT AGREEMENT On June 27, 2003, APS filed a general rate case with the ACC and requested a $175.1 million, or 9.8%, increase in its annual retail electricity revenues, intended to become effective July 1, 2004. In this rate case, APS updated its cost of service and rate design.

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

On 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 groups, and merchant power plant intervenors entered into an agreement that proposes terms under which the rate case would be settled (the "2004 Settlement Agreement").

Key financial components of the 2004 Settlement Agreement, which is subject to ACC approval are as follows:

- APS would receive an annual retail rate increase of approximately $75.5 million, or 4.21%. The increase would consist of an increase in base rates of approximately 3.77% and an increase of approximately 0.44% for recovery over five years of the past costs of compliance with the ACC's retail electric competition rules.

- APS would 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, which would result in a mandatory rate base disallowance of $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.

- To bridge the time between the effective date of the rate increase and the actual date the PWEC Dedicated Assets transfer, APS and Pinnacle West Energy would enter into a cost-based purchase power agreement (the "Bridge PPA"), which would be based on the value of the PWEC Dedicated Assets described in the previous bullet point. The Bridge PPA would remain in effect until the FERC approves the transfer of the PWEC Dedicated Assets to APS and the transfer is completed.
  - If the FERC were to issue an order denying APS' request to acquire the PWEC Dedicated Assets, the Bridge PPA would become a 30-year purchased power agreement, with prices reflecting cost-of-service as if APS had acquired and rate-based the PWEC Dedicated Assets at the value described above.
  - If the FERC were to issue an order (a) approving APS' request to transfer the PWEC Dedicated Assets at a value materially less than $700 million, (b) approving the transfer of fewer than all of the PWEC Dedicated Assets or (c) that was materially inconsistent with the 2004 Settlement Agreement, APS would file an appropriate application with the ACC so that rates could be adjusted. In these circumstances, the Bridge PPA would continue at least until the conclusion of the subsequent proceeding to consider any appropriate adjustment to APS' rates.
- A PSA would provide for the recovery of variations in fuel and purchased power costs, subject to specified parameters and procedures.
- APS would not restore and recover in rates the $234 million write-off recorded in 1999 as a result of the 1999 Settlement Agreement. As a result, annual amortization expense for financial reporting purposes would be approximately $16 million less than if the $234 million write-off had been restored and amortized over a 15-year period as originally requested.
- APS would adopt longer service lives than originally requested for certain depreciable assets, which would have the effect of reducing annual depreciation expense for financial reporting purposes by approximately $26 million.

On February 28, 2005, the administrative law judge in the general rate case issued a recommended order. The recommended order proposes ACC approval of the 2004 Settlement Agreement with two changes related to the PSA. First, the amount of gas costs that APS could recover under the annual PSA would be limited to $500 million per year. Second, although the 2004 Settlement Agreement provides that the PSA would remain in effect for a minimum five-year period, under the recommended order the ACC would be able to eliminate the PSA at any time, if appropriate, if APS files a rate case before the expiration of the five-year period or APS does not comply with the terms of the PSA. If APS exceeds the gas costs that could be recoverable under the PSA or if the ACC eliminates the PSA, APS would retain the right to file a rate case to reset its base rates.

On March 14, 2005, the parties to the 2004 Settlement Agreement jointly filed suggested changes to the recommended order addressing, among other things, the recommended order's proposed treatment of the PSA. The ACC has scheduled open meetings on March 24 and March 28, 2005 to consider the recommended order and suggested changes. APS cannot predict the outcome of this matter.

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

The ACC granted the Financing Order subject to various conditions. One of these conditions is that APS must maintain a common equity ratio of at least forty percent and may not pay common dividends if such payment would reduce its common equity ratio below that threshold, unless otherwise waived by the ACC.

In addition, the Financing Order required the ACC staff to conduct an inquiry into our and our affiliates' compliance with the retail electric competition and related rules and decisions. On June 13, 2003, APS submitted its report on these matters to the ACC staff. As part of the 2004 Settlement Agreement, this inquiry would be concluded with no further action by the ACC.

RETAIL ELECTRIC COMPETITION RULES The Rules approved by the ACC include the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Effective January 1, 2001, retail access became available to all APS retail electricity customers.
- Electric service providers that get CC&N's from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs that unbundle rates for noncompetitive services.
- The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.
- Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates. Under the 1999 Settlement Agreement, APS received a waiver to allow transfer of its competitive electric assets and services to affiliates no later than December 31, 2002. However, as discussed below, in 2002 the ACC reversed its decision, as reflected in the Rules, to require APS to transfer its generation assets.

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, to operate in Arizona. We do not believe the ruling affected the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC appealed the ruling to the Arizona Court of Appeals, and in January 2004, the Court invalidated some, but not all, of the Rules as either violative of Arizona's constitutional requirement that the ACC consider the "fair value" of a utility's property in setting rates or as being beyond the ACC's constitutional and statutory powers. Other Rules were set aside for failure to submit such regulations to the Arizona Attorney General for approval as required by statute. A request for the Arizona Supreme Court to review the Court of Appeals decision was denied on January 4, 2005.

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

- reversed its decision, as reflected in the Rules, to require APS to transfer its generation assets either to an unrelated third party or to a separate corporate affiliate; and
- unilaterally modified the 1999 Settlement Agreement, which authorized APS' transfer of its generating assets, and directed APS to cancel its activities to transfer its generation assets to Pinnacle West Energy.

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

- APS and the ACC staff agreed that it would be appropriate for the ACC to consider the following matters in APS' general rate case, which was filed on June 27, 2003:
  - the generating assets to be included in APS' rate base, including the question of whether the PWEC Dedicated Assets should be included in APS' rate base;
  - the appropriate treatment of the $234 million pretax asset write-off agreed to by APS as part of the 1999 Settlement Agreement; and
  - the appropriate treatment of costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy.

• As a result of the ACC's issuance of the Financing Order, APS' appeals of the Track A Order are limited to the issues described in the preceding bullet points.

On August 27, 2003, APS, Pinnacle West and Pinnacle West Energy filed a lawsuit asserting damage claims relating to the Track A Order. Arizona Public Service Company et al. v. The State of Arizona ex rel., Superior Court of the State of Arizona, County of Maricopa, No. CV2003-016372.

Upon the ACC's issuance of a final, non-appealable order approving the 2004 Settlement Agreement, APS, Pinnacle West, and Pinnacle West Energy will dismiss the litigation described under this "Track A" heading.

TRACK B ORDER On March 14, 2003, the ACC issued the Track B Order, which required APS to solicit bids for certain estimated amounts of capacity and energy for periods beginning July 1, 2003. For 2003, APS was required to solicit competitive bids for about 2,500 MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of APS' total retail energy requirements. APS issued requests for proposals in March 2003 and, by May 6, 2003, APS entered into contracts to meet all or a portion of its requirements for the years 2003 through 2006 as follows:

- Pinnacle West Energy agreed to provide 1,700 MW in July through September of 2003 and in June through September of 2004, 2005 and 2006, by means of a unit contingent contract.
- PPL Energy Plus, LLC agreed to provide 112 MW in July through September of 2003 and 150 MW in June through September of 2004 and 2005, by means of a unit contingent contract.
- Panda Gila River LP agreed to provide 450 MW in October of 2003 and 2004 and May of 2004 and 2005, and 225 MW from November 2003 through April 2004 and from November 2004 through April 2005, by means of firm call options.

Effective upon final ACC approval of the 2004 Settlement Agreement and the closing of the purchase of the Sundance Plant discussed below, the Track B contracts with Pinnacle West Energy and PPL Energy Plus, LLC will be cancelled.

REQUEST FOR PROPOSALS AND ASSET PURCHASE AGREEMENT In early December 2003, APS issued a request for proposals ("2003 RFP") for long-term power supply resources. On June 1, 2004, APS and PPL Sundance, a wholly-owned subsidiary of PPL Corporation, entered into an asset purchase agreement by which APS agreed to purchase the Sundance Plant. The Sundance Plant, which began commercial operation in July 2002, would provide peaking generation support for APS' system and reduce APS' growing needs for new generation resources. The purchase price for the Sundance Plant is approximately $190 million.

On June 1, 2004, APS and PPL Sundance filed a joint application with the ACC with respect to APS' proposed acquisition of the Sundance Plant. On January 20, 2005, the ACC issued an order confirming APS' authority to "self-build or buy new generation assets for native load" and stated that APS' acquisition of the Sundance Plant would be a proper purpose under APS' existing ACC financing authorizations. APS' filings with the ACC also had requested that the ACC allow APS to defer for future recovery certain capital and operating costs (net of fuel and purchased power savings) associated with the Sundance Plant acquisition until rate treatment for the Sundance Plant could be considered in APS' next general rate case. APS' filings estimated that the deferrals would be approximately $10 million to $15 million before income taxes on an annualized basis. The order issued by the ACC allows APS to record the deferrals for up to 36 months, subject to a number of conditions. However, if APS has a general rate case pending at the end of the 36-month period, the deferral period could extend until the rate case had been decided. The conditions imposed by the order are expected to substantially limit the amount of deferrals that APS will be able to record.

APS' acquisition of the Sundance Plant is subject to FERC approval and to customary closing conditions. The transaction is targeted to close in the spring of 2005.

APS does not expect to enter into any additional transactions as a result of the 2003 RFP.

PROVIDER OF LAST RESORT OBLIGATION Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is, under the Rules, the "provider of last resort" for standard-offer, full-service customers under rates that have been approved by the ACC. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, APS may need to purchase additional supplemental power in the wholesale spot market. At various times, prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. There can be no assurance that APS would be able to fully recover the costs of this power. The proposed settlement of APS' general rate case, discussed above, would, among other things, allow APS to recover purchased power costs.

1999 SETTLEMENT AGREEMENT The following are the major provisions of a settlement agreement entered into in 1999, as approved by the ACC:

- APS has reduced rates for standard-offer service for customers with loads less than three MW in a series of annual retail electricity price reductions of 1.5% on July 1 for each of the years 1999 to 2003 for a total of 7.5%. Based on the price reductions authorized in the 1999 Settlement Agreement, there were retail price decreases of approximately $24 million ($14 million after taxes), effective July 1, 1999; approximately $28 million ($17 million after taxes), effective July 1, 2000; approximately $27 million ($16 million after taxes), effective July 1, 2001; approximately $28 million ($17 million after taxes), effective July 1, 2002; and approximately $29 million ($18 million after taxes), effective July 1, 2003. For customers having loads of three MW or greater, standard-offer rates have been reduced in varying annual increments that total 5% in the years 1999 through 2002.

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

- There was a moratorium on retail price changes for standard-offer and unbundled competitive direct access services until July 1, 2004.

- APS is being permitted to defer for later recovery prudent and reasonable costs of complying with the Rules, system benefits costs in excess of the levels included in then-current (1999) rates, and costs associated with the "provider of last resort" and standard-offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004, or when the rate case is decided. See "APS General Rate Case; 2004 Settlement Agreement" above.

- APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the Rules (see "Retail Electric Competition Rules" above), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001.

- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement stated that APS has demonstrated that its allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value (in 1999 dollars). The 1999 Settlement Agreement also stated that APS will not be allowed to recover $183 million net present value (in 1999 dollars) ($234 million pretax) of the $533 million. The 1999 Settlement Agreement provided that APS will have the opportunity to recover $350 million net present value (in 1999 dollars) through a competitive transition charge that will remain in effect through December 31, 2004, at which time it will terminate. The costs subject to recovery under the adjustment clause described above will be decreased or increased by any over/under-recovery of the $350 million due to sales volume variances. As part of its general rate case request, APS sought the recovery of amounts written off by APS as a result of the 1999 Settlement Agreement. That claim would be given up under the terms of the 2004 Settlement Agreement (see above).
- The 1999 Settlement Agreement required APS to form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) its competitive electric assets and services no later than December 31, 2002. The 1999 Settlement Agreement provided that APS would be allowed to defer and later collect, beginning July 1, 2004, 67% of its costs to accomplish the required transfer of generation assets to an affiliate. However, as discussed above under "Track A Order," in 2002 the ACC unilaterally modified this aspect of the 1999 Settlement Agreement by issuing an order preventing APS from transferring its generation assets. Under the 2004 Settlement Agreement, APS would recover all costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy. See "APS General Rate Case; 2004 Settlement Agreement" above. Such full recovery of divestiture costs would be allowed under the 2004 Settlement Agreement (see above).

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

Federal

In July 2002, the FERC adopted a price mitigation plan that constrains the price of electricity in the wholesale spot electricity market in the western United States. The FERC adopted a price cap of $250 per MWh for the period subsequent to October 31, 2002. Sales at prices above the cap must be justified and are subject to potential refund.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking for Standard Market Design for wholesale electric markets. Voluminous comments and reply comments were filed on virtually every aspect of the proposed rule. On April 28, 2003, the FERC Staff issued an additional white paper on the proposed Standard Market Design. The white paper discusses several policy changes to the proposed Standard Market Design, including a greater emphasis on flexibility for regional needs. We cannot currently predict what, if any, impact there may be to the Company if the FERC adopts the proposed rule or any modifications proposed in the comments.

The FERC has been, through its Office of Marker Oversight and Investigations (OMOI), in the process of auditing a number of electric utilities regarding compliance with its regulations. Such an audit of APS and its affiliates was recently completed, and the FERC has issued an order approving the OMOI audit report and directing certain compliance actions. Arizona Public Service Company, 109 FERC 61,271 (2004).

Chief among the FERC's findings, APS must pay $4 million for its use of unauthorized point-to-point transmission service. Of the $4 million, APS must distribute: (1) $2.75 million to upgrade the West Phoenix-Lincoln Street 230kV transmission line with high capacity composite conductors; and (2) $1.25 million as a contribution to established low income energy assistance programs in Arizona. APS must not recover these monies from any existing or future wholesale or retail rate recovery mechanism, nor may it announce the low income payment as a public interest contribution. APS must also take certain corrective actions and make quarterly filings detailing its progress in implementing these actions until all are completed.

APS believes that the resolution of these matters will not have a material adverse effect on its financial position, results of operations or liquidity.

4. INCOME TAXES

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

APS has recorded a regulatory asset and a regulatory liability related to income taxes on its Balance Sheets in accordance with SFAS No. 71. The regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. The regulatory liability relates to excess deferred taxes resulting primarily from the reduction in federal income tax rates as part of the Tax Reform Act of 1986. APS amortizes this amount as the differences reverse.

As a result of a change in IRS guidance, we claimed a tax deduction related to an APS tax accounting method change on the 2001 federal consolidated income tax return. The accelerated deduction resulted in a $200 million reduction in the current income tax liability and a corresponding increase in the plant-related deferred tax liability. In 2002, we received an income tax refund of approximately $115 million related to our 2001 federal consolidated income tax return. The 2001 federal consolidated income tax return is currently under examination by the IRS. As part of this ongoing examination, the IRS is reviewing this accounting method change and the resultant deduction. During 2004, the current income tax liability was increased, with a corresponding decrease to plant-related deferred tax liability, to reflect the expected outcome of this audit. We do not expect the ultimate outcome of this examination to have a material adverse impact on our financial position, results of operations or liquidity.

The income tax liability accounts reflect the tax and interest associated with the most probable resolution of all known and measurable tax exposures.

In 2004 and 2003, we resolved certain prior-year issues with the taxing authorities and recorded tax benefits associated with tax credits and other reductions to income tax expense.

The components of income tax expense are as follows (dollars in thousands):

	Year Ended December 31, 2004	2003	2002
Current:			
Federal	**$ 200,133**	$ 22,875	$ (43,492)
State	**48,054**	3,752	(14,732)
Total current	**248,187**	26,627	(58,224)
Deferred:			
Income from continuing operations	**(113,850)**	81,756	191,135
Discontinued operations	**–**	3,706	5,189
Cumulative effect of accounting change	**–**	–	(43,123)
Total deferred	**(113,850)**	85,462	153,201
Total income tax expense	**134,337**	112,089	94,977
Less: income tax expense/(benefit) on discontinued operations	**5,480**	9,616	(14,045)
Less: income tax benefit for cumulative effect of accounting change	**–**	–	(43,123)
Total income tax expense for income from continuing operations	**$ 128,857**	$ 102,473	$ 152,145

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

	Year Ended December 31, 2004	2003	2002
Federal income tax expense at 35% statutory rate	**$ 127,426**	$ 114,897	$ 136,048
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	**13,705**	11,522	18,114
Credits and favorable adjustments related to prior years resolved in current year	**(6,138)**	(17,944)	–
Medicare Subsidy Part-D (see Note 8)	**(1,778)**	–	–
Allowance for equity funds used during construction (see Note 1)	**(1,547)**	(4,984)	–
Other	**(2,811)**	(1,018)	(2,017)
Income tax expense	**$ 128,857**	$ 102,473	$ 152,145

The following table sets forth the net deferred income tax liability recognized on the Consolidated Balance Sheets (dollars in thousands):

	December 31, 2004	2003
Current liability	**$ (9,057)**	$ (631)
Long term liability	**(1,227,553)**	(1,338,527)
Accumulated deferred income taxes – net	**$ (1,236,610)**	$ (1,339,158)

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

	December 31, 2004	December 31, 2003
DEFERRED TAX ASSETS		
Regulatory liabilities:		
Asset Retirement Obligation	**$ 182,086**	$ 169,322
Federal excess deferred income taxes	**16,341**	18,936
Other	**8,282**	8,302
Pension liability	**91,973**	73,844
Risk management and trading activities	**91,021**	59,293
Deferred gain on Palo Verde Unit 2 sale leaseback	**19,816**	21,656
Other	**70,849**	64,770
Total deferred tax assets	**480,368**	416,123
DEFERRED TAX LIABILITIES		
Plant-related	**(1,516,174)**	(1,614,887)
Risk management and trading activities	**(146,037)**	(84,124)
Regulatory assets	**(54,767)**	(56,270)
Total deferred tax liabilities	**(1,716,978)**	(1,755,281)
Accumulated deferred income taxes – net	**$ (1,236,610)**	$ (1,339,158)

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

APS had committed lines of credit with various banks of $325 million at December 31, 2004 and $250 million at December 31, 2003, which were available either to support the issuance of up to $250 million in commercial paper or to be used for bank borrowings, including issuance of letters of credit. The current line matures in May 2007. The commitment fees at December 31, 2004 and 2003 for these lines of credit were 0.15% and 0.175% per annum. APS had no bank borrowings outstanding under these lines of credit at December 31, 2004 and 2003. APS had approximately $4.8 million letters of credit issued under the line at December 31, 2004.

APS had no commercial paper borrowings outstanding at December 31, 2004 and 2003. By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

Pinnacle West had committed lines of credit of $300 million at December 31, 2004 and $275 million at December 31, 2003, which were available either to support the issuance of up to $250 million in commercial paper or to be used for bank borrowings, including issuance of letters of credit. The current lines mature in October 2007. Pinnacle West had no outstanding borrowings at December 31, 2004 and December 31, 2003. Pinnacle West had approximately $13 million of letters of credit issued under the line at December 31, 2004 and approximately $15 million of letters of credit issued under the line at December 31, 2003. The commitment fees were 0.175% in 2004 and ranged from 0.125% to 0.175% in 2003. Pinnacle West had no commercial paper borrowings outstanding at December 31, 2004 and 2003. All APS and Pinnacle West bank lines of credit and commercial paper agreements are unsecured.

SunCor had revolving lines of credit totaling $90 million at December 31, 2004 and $120 million at December 31, 2003. The commitment fees were 0.125% in 2004 and 2003. SunCor had $35 million outstanding at December 31, 2004 and $50 million outstanding at December 31, 2003. The weighted-average interest rate was 4.50% at December 31, 2004 and 2003. Interest for 2004 and 2003 was based on LIBOR plus 2% or prime plus 0.5%. The balance is included in short-term debt on the Consolidated Balance Sheets. SunCor had other short-term loans in the amount of $36 million at December 31, 2004 and December 31, 2003. These loans are made up of multiple notes primarily with variable interest rates based on LIBOR plus 2.5% at December 31, 2004 and 2003.

6. LONG-TERM DEBT

APS has retired all first mortgage bonds issued 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. SunCor's short and long-term debt is collateralized by interests in certain real property and Pinnacle West's debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding at December 31, 2004 and 2003 (dollars in thousands):

			December 31,	
	Maturity Dates (a)	Interest Rates	**2004**	2003
APS				
First mortgage bonds (b)	2004	6.625%	**$ –**	$ 80,000
First mortgage bonds (c)	2028	5.50%	**–**	25,000
First mortgage bonds (d)	2028	5.875%	**–**	154,000
Unamortized discount and premium			**(7,968)**	(8,631)
Pollution control bonds (e)	2024-2034	(f)	**565,860**	386,860
Pollution control bonds with senior notes	2029	5.05%	**90,000**	90,000
Unsecured notes (g)	2004	5.875%	**–**	125,000
Unsecured notes	2005	6.25%	**100,000**	100,000
Unsecured notes	2005	7.625%	**300,000**	300,000
Unsecured notes	2011	6.375%	**400,000**	400,000
Unsecured notes	2012	6.50%	**375,000**	375,000
Unsecured notes	2033	5.625%	**200,000**	200,000
Unsecured notes	2015	4.650%	**300,000**	300,000
Unsecured notes (h)	2014	5.80%	**300,000**	–
Secured note	2014	6.00%	**1,900**	–
Senior notes (i)	2006	6.75%	**83,695**	83,695
Capitalized lease obligations	2006-2012	(j)	**9,854**	11,749
Subtotal			**2,718,341**	2,622,673
SUNCOR				
Notes payable	2006-2008	(k)	**15,467**	17,125
Capitalized lease obligations	2005-2007	8.91%	**507**	728
Subtotal			**15,974**	17,853
PINNACLE WEST				
Senior notes (l)	2006	6.40%	**302,589**	515,000
Unamortized discount and premium			**(143)**	(270)
Floating rate senior notes	2005	(m)	**165,000**	165,000
Capitalized lease obligations	2005-2007	5.45%	**389**	1,243
Subtotal			**467,835**	680,973
Total long-term debt (n)			**3,202,150**	3,321,499
Less current maturities (n)			**617,165**	704,914
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			**$ 2,584,985**	$ 2,616,585

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

(b) On March 1, 2004, APS redeemed at maturity $80 million of its First Mortgage Bonds, 6.625% Series due 2004.

(c) On March 31, 2004, APS redeemed $25 million of its First Mortgage Bonds, 5.5% Series due 2028.

(d) On March 31, 2004, APS redeemed $154 million of its First Mortgage Bonds, 5.875% Series due 2028.

(e) 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 (see (c) above) and $141 million of the Navajo 5.875% bonds due 2028 (see (d) above). 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. 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 (see (d) above). 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.

(f) The weighted-average rate was 1.89% at December 31, 2004 and 1.51% at December 31, 2003. Changes in short-term interest rates would affect the costs associated with this debt.

(g) On February 15, 2004, APS redeemed at maturity $125 million of its 5.875% Notes due 2004.

(h) 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.

(i) Through April 30, 2004, APS had outstanding $84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes, as well as the $90 million issue due in 2029. The senior note mortgage bonds had the same interest rate, interest payment dates, maturity and redemption provisions as the senior notes. As long as the senior note mortgage bonds secured the senior notes, the senior notes effectively ranked equally with the first mortgage bonds. On April 30, 2004, when APS repaid all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds were released from the senior note indenture, resulting in their no longer securing the senior notes and ceasing to be outstanding.

(j) The weighted average rate was 5.78% at December 31, 2004 and 5.55% at December 31, 2003. Capital leases are included in property, plant and equipment on the Consolidated Balance Sheets for both December 31, 2004 and December 31, 2003.

(k) Multiple notes with variable interest rates based on the lenders' prime plus 0.25%, lenders' prime plus 1.75% and LIBOR plus 2.50%. There are also two notes at fixed rates of 8.00% and 10.00%.

(l) On January 29, 2004, we entered into a fixed-for-floating interest rate swap transaction on the $300 million 6.40% senior note. The transaction qualifies as a fair value hedge under SFAS No. 133.

(m) The weighted average rate was 2.06% at December 31, 2004 and 1.98% at December 31, 2003.

(n) $281 million of pollution control bonds at December 31, 2003 have been reclassified from long-term to current maturities. The bond holders had the ability to put these bonds to APS in the short-term on the interest rate reset date. Without a demonstrated intent to finance on a long-term basis (by use of credit agreements that extend for more than one year, etc.), GAAP requires the classification of the obligations as current maturities.

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 those and 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 our 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.

The following is a list of principal payments due on Pinnacle West's total long-term debt and capitalized lease requirements:

- $618 million in 2005;
- $398 million in 2006;
- $174 million in 2007;
- $7 million in 2008;
- $1 million in 2009; and
- $2,012 million, thereafter.

7. COMMON STOCK AND TREASURY STOCK

Our common stock and treasury stock activity during each of the three years 2004, 2003 and 2002 is as follows (dollars in thousands):

	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount
Balance at December 31, 2001	84,824,947	$ 1,536,924	(101,307)	$ (5,886)
Common stock issuance	6,555,000	199,238	–	–
Purchase of treasury stock	–	–	(150,500)	(5,971)
Reissuance of treasury stock for stock compensation (net)	–	–	126,977	7,499
Other	–	1,096	–	–
Balance at December 31, 2002	91,379,947	1,737,258	(124,830)	(4,358)
Reissuance of treasury stock for stock compensation (net)	–	–	32,815	1,085
Other	–	7,096	–	–
Balance at December 31, 2003	91,379,947	1,744,354	(92,015)	(3,273)
Common stock issuance	**422,914**	**18,291**	**–**	**–**
Purchase of treasury stock	**–**	**–**	**(80,000)**	**(2,986)**
Reissuance of treasury stock for stock compensation (net)	**–**	**–**	**162,493**	**5,831**
Other	**–**	**6,402**	**–**	**–**
Balance at December 31, 2004	**91,802,861**	**$ 1,769,047**	**(9,522)**	**$ (428)**

8. RETIREMENT PLANS AND OTHER BENEFITS

Pinnacle West sponsors a qualified defined benefit and account balance pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. Effective January 1, 2003, Pinnacle West sponsored a new account balance plan for all new employees in place of the defined benefit plan and, as of April 1, 2003, the plan was offered as an alternative to the defined benefit plan for all existing employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all of our employees. The supplemental excess benefit retirement plan covers officers of the Company and highly compensated employees designated for participation by the Board of Directors. Our employees do not contribute to the plans. Generally, we calculate the benefits based on age, years of service and pay.

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

Pinnacle West uses a December 31 measurement date for its pension and other postretirement benefit plans.

On December 8, 2003, the President signed the “Medicare Prescription Drug, Improvement and Modernization Act of 2003” (the Act). One feature of the Act is a government subsidy of prescription drug cost. The FASB issued FSP 106-2, “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003,” to address the accounting for the effects of the Act. During the third quarter of 2004, we retroactively adopted the provisions of FSP 106-2, resulting in the remeasurement of our postretirement benefit plans’ accumulated postretirement benefit obligation as of December 31, 2003. The impact of the subsidy is a decrease in the accumulated projected benefit obligation of approximately $65 million and a decrease of approximately $11 million in the net periodic postretirement benefit cost for 2004. The 2004 after-tax reduction to expense is approximately $5 million, excluding amounts capitalized as construction overhead or billed to electric plant participants.

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

	Pension			Other Benefits		
	2004	2003	2002	**2004**	2003	2002
Service cost – benefits earned during the period	**$ 41,207**	$ 37,662	$ 30,333	**$ 17,557**	$ 15,858	$ 12,036
Interest cost on benefit obligation	**81,873**	76,951	71,242	**29,488**	30,163	25,235
Expected return on plan assets	**(78,790)**	(65,046)	(75,652)	**(24,773)**	(18,762)	(21,116)
Amortization of:						
Transition (asset)/obligation	**(3,227)**	(3,227)	(3,227)	**3,005**	3,005	4,001
Prior service cost/(credit)	**2,401**	2,401	2,912	**(125)**	(125)	(75)
Net actuarial loss	**17,946**	18,135	1,846	**7,414**	9,714	3,072
Net periodic benefit cost	**$ 61,410**	$ 66,876	$ 27,454	**$ 32,566**	$ 39,853	$ 23,153
Portion of cost charged to expense	**$ 25,792**	$ 30,094	$ 13,727	**$ 13,678**	$ 17,934	$ 11,577
APS share of costs charged to expense	**$ 22,483**	$ 25,450	$ 10,947	**$ 11,923**	$ 15,166	$ 9,232

The following table sets forth the plans' changes in the benefit obligations for the plan years 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	**2004**	2003
Benefit obligation at January 1	**$ 1,307,628**	$ 1,069,577	**$ 540,181**	$ 409,874
Service cost	**41,207**	37,662	**17,557**	15,858
Interest cost	**81,873**	76,951	**29,488**	30,163
Benefit payments	**(45,195)**	(43,869)	**(14,332)**	(15,749)
Actuarial losses/(gains)	**68,731**	171,420	**(36,681)**	106,475
Plan amendments	**–**	(4,113)	**–**	(6,440)
Benefit obligation at December 31	**$ 1,454,244**	$ 1,307,628	**$ 536,213**	$ 540,181

The following table sets forth the qualified pension plan and other benefit plan changes in the fair value of plan assets for the years 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	**2004**	2003
Fair value of plan assets at January 1	**$ 887,311**	$ 720,807	**$ 294,051**	$ 223,474
Actual return on plan assets	**102,829**	162,571	**32,433**	46,071
Employer contributions	**35,000**	46,000	**32,600**	39,852
Benefit payments	**(42,858)**	(42,067)	**(7,000)**	(15,346)
Fair value of plan assets at December 31	**$ 982,282**	$ 887,311	**$ 352,084**	$ 294,051

The following table shows a reconciliation of the funded status of the plans to the amounts recognized on the Consolidated Balance Sheets as of December 31, 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	**2004**	2003
Funded status at December 31	**$ (471,962)**	$ (420,317)	**$ (184,129)**	$ (246,130)
Unrecognized net transition (asset)/obligation	**(3,873)**	(7,099)	**24,039**	27,044
Unrecognized prior service cost/(credit)	**14,234**	16,634	**(1,422)**	(1,547)
Unrecognized net actuarial losses	**375,980**	348,982	**158,271**	217,611
Benefit liability recognized in the Consolidated Balance Sheets	**$ (85,621)**	$ (61,800)	**$ (3,241)**	$ (3,022)

The following sets forth the details related to benefits included on the Consolidated Balance Sheets at December 31, 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	**2004**	2003
Accrued benefit cost	**$ (85,621)**	$ (61,800)	**$ (3,241)**	$ (3,022)
Additional minimum liability	**(148,824)**	(126,241)	**–**	–
Total liability	**(234,445)**	(188,041)	**(3,241)**	(3,022)
Intangible asset	**14,234**	16,634	**–**	–
Accumulated other comprehensive loss (pretax)	**134,590**	109,607	**–**	–
Net amount recognized	**$ (85,621)**	$ (61,800)	**$ (3,241)**	$ (3,022)

The following table sets forth the other comprehensive income arising from the change in additional minimum liability for the years ended December 31, 2004 and 2003 (dollars in thousands):

	2004	2003
Decrease/(increase) in minimum liability included in other comprehensive income – net of tax:		
Pinnacle West consolidated	**$ (15,225)**	$ 4,700
APS share	**$ (13,930)**	$ 4,329

The following table sets forth the projected benefit obligation and the accumulated benefit obligation for pension plans in excess of plan assets for the plan years 2004 and 2003 (dollars in thousands):

	Year Ended December 31,	
	2004	2003
Projected benefit obligation	**$ 1,454,244**	$ 1,307,628
Accumulated benefit obligation	**$ 1,216,727**	$ 1,075,352
Less fair value of plan assets	**982,282**	887,311
Pinnacle West pension liability	**$ 234,445**	$ 188,041
APS share of pension liability	**$ 203,668**	$ 160,639

Below are the weighted-average assumptions for both the pension and other benefits used to determine each respective benefit obligation and net periodic benefit cost:

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,	
	2004	2003	**2004**	2003
Discount rate – pension	**5.84%**	6.10%	**6.10%**	6.75%
Discount rate – other benefits	**5.92%**	6.10%	**6.10%**	6.75%
Rate of compensation increase	**4.00%**	4.00%	**4.00%**	4.00%
Expected long-term return on plan assets	**N/A**	N/A	**9.00%**	9.00%
Initial health care cost trend rate	**8.00%**	8.00%	**8.00%**	8.00%
Ultimate health care cost trend rate	**5.00%**	5.00%	**5.00%**	5.00%
Year ultimate health care trend rate is reached	**2009**	2008	**2008**	2007

In selecting the pretax expected long-term rate of return on plan assets we consider past performance and economic forecasts for the types of investments held by the plan. For the year 2005, we are assuming a 9% rate of return on plan assets. As recent history has demonstrated, markets may decline and increase dramatically. However, we believe the long-term rate of return on plan assets of 9% is reasonable given our asset allocation in relation to historical and expected future performance.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in the assumed initial and ultimate health care cost trend rates would have the following effects (dollars in millions):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	$ 6	$ (5)
Effect on service and interest cost components of net periodic other postretirement benefit costs	$ 10	$ (8)
Effect on the accumulated other postretirement benefit obligation	$ 96	$ (76)

Plan Assets

Pinnacle West's qualified pension plan asset allocation at December 31, 2004 and 2003 is as follows:

	Percentage of Plan Assets at December 31,		Target Asset
	2004	2003	Allocation
ASSET CATEGORY			
Equity securities	**60%**	65%	60%
Fixed Income	**27**	23	30%
Other	**13**	12	10%
Total	**100%**	100%	

The Board of Directors has established an investment policy for the pension plan assets and has delegated oversight of the plan assets to an Investment Management Committee. The investment policy sets forth the objective of providing for future pension benefits by maximizing return consistent with acceptable levels of risk. The primary investment strategies are diversification of assets, stated asset allocation targets and ranges, prohibition of investments in Pinnacle West securities, and external management of plan assets.

Pinnacle West's other postretirement benefit plans' asset allocation at December 31, 2004 and 2003, is as follows:

	Percentage of Plan Assets at December 31,		Target Asset
	2004	2003	Allocation
ASSET CATEGORY			
Equity securities	**71%**	71%	70%
Fixed Income	**23**	25	27%
Other	**6**	4	3%
Total	**100%**	100%	

The Investment Management Committee, described above, has also been delegated oversight of the plan assets for the postretirement benefit plans. The investment policy for other postretirement benefit plans assets is similar to that of the pension plan assets described above.

Contributions

The minimum required contribution to be made to our pension plan in 2005 is estimated to be approximately $50 million. The contribution to be made to other postretirement benefit plans in 2005 is estimated to be approximately $40 million. APS' share is approximately 92% of both plans.

Estimated Future Benefit Payments

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter are estimated to be as follows (dollars in thousands):

	Pension	Other Benefits (a)
2005	$ 47,365	$ 15,595
2006	50,848	15,470
2007	54,381	16,947
2008	59,021	18,404
2009	64,858	20,095
Years 2010-2014	443,578	139,329

(a) The expected future other benefit payments take into account the Medicare Part D subsidy.

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and subsidiaries. In 2004, APS represented 91% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account. Under this plan, the Company matches a percentage of the participants' contributions in the form of Pinnacle West stock. After a five year vesting period, participants have an option to transfer the Company matching contributions out of the Pinnacle West Stock Fund to other investment funds within the plan. At December 31, 2004, approximately 22% of total plan assets were in Pinnacle West stock. Pinnacle West recorded expenses for this plan of approximately $5 million for each of the years 2004, 2003 and 2002. APS recorded expenses for this plan of approximately $5 million in 2004, $5 million in 2003 and $4 million in 2002.

9. LEASES

In 1986, APS sold about 42% of its share of Palo Verde Unit 2 and certain common facilities in three separate sale leaseback transactions. APS accounts for these leases as operating leases. The gain resulting from the transaction of approximately $140 million was deferred and is being amortized to operations and maintenance expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Rent expense is calculated on a straight-line basis. See Note 20 for a discussion of VIEs, including the SPEs involved in the Palo Verde sale leaseback transactions.

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

Total lease expense recognized in the Consolidated Statements of Income was $69 million in 2004, $67 million in 2003 and $67 million in 2002.

The amounts to be paid for the Palo Verde Unit 2 leases are approximately $49 million per year for the years 2005 to 2015.

Estimated future minimum lease payments for Pinnacle West's operating leases are approximately as follows (dollars in millions):

Year	
2005	$ 73
2006	70
2007	69
2008	67
2009	65
Thereafter	368
Total future lease commitments	$ 712

10. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. Pinnacle West Energy shares ownership of its Silverhawk Plant. Our share of operating and maintaining these facilities is included in the Consolidated Statements of Income in operations and maintenance expense. The following table shows APS' and Pinnacle West Energy's interests in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2004 (dollars in thousands):

	Percent Owned	Plant in Service	Accumulated Depreciation	Construction Work in Progress
APS				
Generating Facilities:				
Palo Verde Units 1 and 3	**29.1%**	**$ 1,877,846**	**$ (915,611)**	**$ 51,914**
Palo Verde Unit 2 (see Note 9)	**17.0%**	**665,994**	**(253,083)**	**15,816**
Four Corners Units 4 and 5	**15.0%**	**147,067**	**(83,525)**	**457**
Navajo Generating Station Units 1, 2, and 3	**14.0%**	**248,509**	**(117,922)**	**2,132**
Cholla common facilities (a)	**62.4%(b)**	**80,122**	**(47,134)**	**1,553**
Transmission Facilities:				
ANPP500KV System	**35.8%(b)**	**67,762**	**(27,898)**	**1,026**
Navajo Southern System	**31.4%(b)**	**27,044**	**(16,880)**	**1,576**
Palo Verde – Yuma 500KV System	**23.9%(b)**	**10,347**	**(4,545)**	**26**
Four Corners Switchyards	**27.5%(b)**	**2,852**	**(1,801)**	**–**
Phoenix – Mead System	**17.1%(b)**	**36,418**	**(2,723)**	**–**
Palo Verde – Estrella 500KV System	**55.5%(b)**	**72,613**	**(2,907)**	**841**
Palo Verde – Southeast Valley Project	**15.0%(b)**	**–**	**–**	**1,136**
Harquahala	**80.0%(b)**	**–**	**–**	**10**
PINNACLE WEST ENERGY				
Generating Facilities:				
Silverhawk	**75.0%**	**301,288**	**(6,954)**	**21**

(a) PacifiCorp owns Cholla Unit 4 and APS operates the unit for PacifiCorp. The common facilities at Cholla are jointly-owned.
(b) Weighted average of interests.

11. COMMITMENTS AND CONTINGENCIES

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

Nuclear power plant operators are required to enter into spent fuel disposal contracts with the DOE, and the DOE is required to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE has announced that the repository cannot be completed before 2010 and it does not intend to begin accepting spent nuclear fuel prior to that date. In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision preventing the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities, including APS (on behalf of itself and the other Palo Verde owners), filed damages actions against the DOE in the Court of Federal Claims. Arizona Public Service Company v. United States of America, United States Court of Federal Claims, 03-2832C.

In February 2002, the Secretary of Energy recommended to President Bush that the Yucca Mountain, Nevada site be developed as a permanent repository for spent nuclear fuel. The President transmitted this recommendation to Congress and the State of Nevada vetoed the President's recommendation. Congress approved the Yucca Mountain site, overriding the Nevada veto. The State of Nevada has filed several lawsuits relating to the Yucca Mountain site. We cannot currently predict what further steps will be taken in this area.

APS has existing fuel storage pools at Palo Verde and is operating a new facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, APS believes spent nuclear fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit. Although some low-level waste has been stored on-site in a low-level waste facility, APS is currently shipping low-level waste to off-site facilities. APS currently believes interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

APS currently estimates it will incur $115 million (in 2004 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2004, APS had spent $11 million for on-site interim spent nuclear fuel storage. APS has recorded a regulatory asset of $11 million and is currently seeking recovery of these costs through future rates (see "APS General Rate Case; 2004 Settlement Agreement" in Note 3).

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

Nuclear Insurance

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $300 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $101 million, subject to an annual limit of $10 million per incident. Based on APS' interest in the three Palo Verde units, APS' maximum potential assessment per incident for all three units is approximately $88 million, with an annual payment limitation of approximately $9 million.

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

Purchased Power and Fuel Commitments

APS and Pinnacle West are parties to various purchased power and fuel contracts with terms expiring from 2005 through 2025 that include required purchase provisions. We estimate the contract requirements to be approximately $187 million in 2005; $90 million in 2006; $81 million in 2007; $66 million in 2008; $68 million in 2009 and $363 million thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various purchased power and fuel contracts mentioned above some of those contracts have take-or-pay provisions. The contracts APS has for the supply of its coal supply have take-or-pay provisions. The current take-or-pay coal contracts have terms that expire in 2016.

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

	Estimated Years Ending December 31,					
	2005	2006	2007	2008	2009	Thereafter
Coal take-or-pay commitments (a)	$ 48	$ 48	$ 49	$ 42	$ 44	$ 311

(a) Total take-or-pay commitments are approximately $542 million. The total net present value of these commitments is approximately $389 million.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS' coal mine reclamation obligation was $61 million at December 31, 2004 and $60 million at December 31, 2003 and is included in deferred credits-other on the Consolidated Balance Sheets.

California Energy Market Issues and Refunds in the Pacific Northwest

FERC

In July 2001, the FERC ordered an expedited fact-finding hearing to calculate refunds for spot market transactions in California during a specified time frame. APS was a seller and a purchaser in the California markets at issue, and to the extent that refunds are ordered, APS should be a recipient as well as a payor of such amounts. The FERC is still considering the evidence and refund amounts have not yet been finalized. APS does not anticipate material changes in its exposure and still believes, subject to the finalization of the revised proxy prices, that it will be entitled to a net refund.

On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including the Company, failed to properly file rate information at the FERC in connection with sales to California from 2000 to the present under market-based rates. State of California v. British Columbia Power Exchange et al., Docket No. EL02-71-000. The complaint requests the FERC to require the wholesale sellers to refund any rates that are "found to exceed just and reasonable levels." This complaint was dismissed by the FERC and the State of California appealed the matter to the Ninth Circuit Court of Appeals. In an order issued September 9, 2004, the Ninth Circuit upheld the FERC's authority to permit market-based rates, but rejected the FERC's claim that it was without authority to consider retroactive refunds when a utility has not strictly adhered to the quarterly reporting requirements of the market-based rate system. On September 9, 2004, the Ninth Circuit remanded the case to the FERC for further proceedings. State of California ex rel. Bill Lockyer, Attorney General v. FERC, No. 02-73093. Several of the intervenors in this appeal filed a petition for rehearing of this decision on October 25, 2004. The outcome of the further proceedings cannot be predicted at this time.

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

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

California Civil Energy Market Litigation

The State of California and others have filed various claims, which have now been consolidated, against several power suppliers to California alleging antitrust violations. Wholesale Electricity Antitrust Cases I and II, Superior Court in and for the County of San Diego, Proceedings Nos. 4204-00005 and 4204-00006. Two of the suppliers who were named as defendants in those matters, Reliant Energy Services, Inc. (and other Reliant entities) and Duke Energy and Trading, LLP (and other Duke entities), filed cross-claims against various other participants in the PX and California independent system operator markets, including APS, attempting to expand those matters to such other participants. APS has not yet filed a responsive pleading in the matter, but APS believes the claims by Reliant and Duke as they relate to APS are without merit.

APS was also named in a lawsuit regarding wholesale contracts in California, which, after moving to state court, has been removed to the federal court for a second time. James Millar, et al. v. Allegheny Energy Supply, et al., San Francisco Superior Court, Case No. 407867, U.S. District Court (Northern District) C-04-0519 SBA. The First Amended Complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market, in violation of California unfair competition laws.

The PX has filed a lawsuit against the State of California regarding the seizure of forward contracts and the State has filed a cross complaint against APS and numerous other PX participants. Cal PX v. The State of California, Superior Court in and for the County of Sacramento, JCCP No. 4203. Various motions continue to be filed, and we currently believe these claims will have no material adverse impact on our financial position, results of operations or liquidity.

Construction Program

Consolidated capital expenditures in 2005 are estimated to be (dollars in millions):

APS	$ 772
Pinnacle West Energy	7
SunCor	114
Other	8
Total	$ 901

Natural Gas Supply

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

On July 9, 2003, the FERC issued an order that altered the capacity rights of parties to the 1996 settlement, but maintained the cost responsibility provisions agreed to by parties to that settlement. The D.C. Court of Appeals recently upheld the FERC's authority to alter the capacity rights of parties to the settlement. With respect to the FERC's authority to maintain the cost of responsibility provisions of the settlement, a party has sought appellate review and is seeking to reallocate the costs responsibility associated with the changed contractual obligations in a way that would be less favorable to APS and Pinnacle West Energy than under the FERC's July 9, 2003 order. Should this party prevail on this point, APS and Pinnacle West Energy's annual capacity cost could be increased by approximately $3 million per year, from September 2003 through December 2005.

El Paso is required under the terms of the 1996 settlement to file a new rate case by July 1, 2005, with new rates to become effective on January 1, 2006. APS cannot currently assess the financial impact that El Paso's filing could have on rates.

Navajo Nation Litigation

In June 1999, the Navajo Nation served Salt River project with a lawsuit naming Salt River Project, several Peabody Coal Company entities (collectively, "Peabody"), Southern California Edison Company and other defendants, and citing various claims in connection with the renegotiations of the coal royalty and lease agreements under which Peabody mines coal for the Navajo Generating Station and the Mohave Generating Station. The Navajo Nation v. Peabody Holding Company, Inc., et al., United States District Court for the District of Columbia, CA-99-0469-EGS (the "D.C. Lawsuit"). APS is a 14% owner of the Navajo Generating Station, which, Salt River Project operates. The D.C. Lawsuit alleges, among other things, that the defendants obtained a favorable coal royalty rate by improperly influencing the outcome of a federal administrative process under which the royalty rate was to be adjusted. The suit seeks $600 million in damages, treble damages, punitive damages of not less than $1 billion, and the ejection of defendants "from all possessory interests and Navajo Tribal lands arising out of the (primary coal lease)." In July 2001, the court dismissed all claims against Salt River Project.

In January, 2005, Peabody served APS with a lawsuit naming APS and the other Navajo Generating Station participants and seeking, among other things, a declaration that the participants "are obligated to reimburse Peabody for any royalty tax, or other obligation arising out of the D.C. Lawsuit". Peabody Western Coal Company v. Salt River Project Agricultural Improvement and Power District, et al., Circuit Court for the City of St. Louis, Division No. 1, Cause No. 042-08561. Based on APS' ownership interest in the Navajo Generating Station, APS could be liable for up to 14% of any such obligation. Because the litigation is in preliminary stages, APS cannot currently predict the outcome of this matter.

Litigation

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

12. ASSET RETIREMENT OBLIGATIONS

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

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. APS invests the trust funds in fixed income and domestic equity securities and classifies them as available for sale. The following table shows the cost and fair value of APS' nuclear decommissioning trust fund assets which are on the Consolidated Balance Sheets at December 31, 2004 and December 31, 2003 (dollars in millions):

	December 31,	
	2004	2003
Trust fund assets – at cost		
Fixed income securities	**$ 134**	$ 124
Domestic stock	**83**	74
Total	**$ 217**	$ 198
Trust fund assets – at fair value		
Fixed income securities	**$ 150**	$ 140
Domestic stock	**118**	101
Total	**$ 268**	$ 241

The following schedule shows the change in our asset retirement obligations during the years ended December 31, 2004 and 2003 (dollars in millions):

	2004	2003
At beginning of year	**$ 234**	$ 219
Changes attributable to:		
Liabilities incurred	**–**	–
Liabilities settled	**(1)**	–
Accretion expense	**17**	15
Estimated cash flow revisions	**2**	–
At end of year	**$ 252**	$ 234

In accordance with SFAS No. 71, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal. At December 31, 2004, regulatory liabilities shown on Pinnacle West's Consolidated Balance Sheets included approximately $462 million of estimated future removal costs that are not considered legal obligations.

13. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following note presents quarterly financial information for 2004 and 2003. We are disclosing originally reported amounts and revised amounts in the first and second quarters of 2004 due to the adoption of FSP 106-2, which was implemented on June 30, 2004 (see Note 8) and in each period for the reclassification of NAC as discontinued operations (see Note 22).

Consolidated quarterly financial information for 2004 and 2003 is as follows (dollars in thousands, except per share amounts):

	2004 Quarter Ended				2004
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total
As originally reported:					
Operating Revenues	$ 574,369	$ 722,686	$ 886,779	$ 734,718	$ 2,918,552
Operations and Maintenance	138,656	140,245	160,765	159,431	599,097
Operating Income	83,371	121,160	210,836	90,745	506,112
Income Taxes	15,627	44,027	58,900	11,283	129,837
Income from Continuing Operations	29,768	71,057	103,886	29,318	234,029
Net Income (a)	30,156	71,370	105,400	33,729	240,655
NAC Reclassifications (see Note 22):					
Operating Revenues	(8,024)	(10,803)	–	–	(18,827)
Operating Income	(443)	(1,950)	–	–	(2,393)
Income Taxes	(159)	(821)	–	–	(980)
Income from Continuing Operations	(247)	(1,104)	–	–	(1,351)
Medicare Subsidy Adoption (See Note 8):					
Operations and Maintenance	(1,270)	(1,270)	–	–	(2,540)
Operating Income	1,270	1,270	–	–	2,540
Income from Continuing Operations	1,270	1,270	–	–	2,540
Net Income	1,270	1,270	–	–	2,540
After NAC Reclassifications and Medicare Subsidy Adoption:					
Operating Revenues	566,345	711,883	886,779	734,718	2,899,725
Operations and Maintenance	137,386	138,975	160,765	159,431	596,557
Operating Income	84,198	120,480	210,836	90,745	506,259
Income Taxes	15,468	43,206	58,900	11,283	128,857
Income from Continuing Operations	30,791	71,223	103,886	29,318	235,218
Net Income (a) (b)	31,426	72,640	105,400	33,729	243,195

	2003 Quarter Ended				2003
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total
As originally reported:					
Operating Revenues	$ 552,643	$ 683,302	$ 847,703	$ 734,204	$ 2,817,852
Operating Income	69,255	132,482	198,850	81,466	482,053
Income Taxes	12,754	35,248	50,528	7,030	105,560
Income from Continuing Operations	20,153	54,889	109,538	45,996	230,576
Net Income (a)	25,298	56,142	110,048	49,091	240,579
NAC Reclassifications (see Note 22):					
Operating Revenues	(11,382)	(19,637)	(16,701)	(10,638)	(58,358)
Operating Income	(3,675)	(1,347)	(1,489)	(1,600)	(8,111)
Income Taxes	(1,402)	(507)	(567)	(611)	(3,087)
Income from Continuing Operations	(2,167)	(783)	(878)	(945)	(4,773)
Reclassified:					
Operating Revenues	541,261	663,665	831,002	723,566	2,759,494
Operating Income	65,580	131,135	197,361	79,866	473,942
Income Taxes	11,352	34,741	49,961	6,419	102,473
Income from Continuing Operations	17,986	54,106	108,660	45,051	225,803
Net Income (a) (b)	25,298	56,142	110,048	49,091	240,579

(a) Includes income from discontinued operations at SunCor (see Note 22).
(b) Includes income (loss) from NAC's discontinued operations (see Note 22).

	2004 Quarter Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
As originally reported – Basic earnings per share (a):				
Income From Continuing Operations	**$ 0.33**	**$ 0.78**	**$ 1.14**	**$ 0.32**
Net Income	**0.33**	**0.78**	**1.15**	**0.37**
After NAC reclassification and Medicare subsidy adoption – Basic earnings per share (a):				
Income from Continuing Operations	**0.34**	**0.78**	**1.14**	**0.32**
Net Income	**0.34**	**0.80**	**1.15**	**0.37**
As originally reported – Diluted earnings per share (a):				
Income From Continuing Operations	**0.33**	**0.78**	**1.14**	**0.32**
Net Income	**0.33**	**0.78**	**1.15**	**0.37**
After NAC reclassification and Medicare subsidy adoption – Diluted earnings per share (a):				
Income From Continued Operations	**0.34**	**0.78**	**1.14**	**0.32**
Net Income	**0.34**	**0.79**	**1.15**	**0.37**

	2003 Quarter Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
As originally reported – Basic earnings per share (b):				
Income From Continuing Operations	$ 0.22	$ 0.60	$ 1.20	$ 0.50
Net Income	0.28	0.62	1.21	0.54
Reclassified – Basic earnings per share (b):				
Income From Continuing Operations	0.20	0.59	1.19	0.49
Net Income	0.28	0.62	1.21	0.54
As originally reported – Diluted earnings per share (b):				
Income From Continuing Operations	0.22	0.60	1.20	0.50
Net Income	0.28	0.61	1.20	0.54
Reclassified – Diluted earnings per share (b):				
Income From Continued Operations	0.20	0.59	1.19	0.49
Net Income	0.28	0.61	1.20	0.54

(a) The difference between originally reported and revised basic and diluted earnings per share related to the sale of NAC (see Note 22) and the adoption of the Medicare subsidy which changed reported amounts for the first and second quarter of 2004 (See Note 8). The earnings per share impact from the sale of NAC or the adoption of the Medicare subsidy did not change earnings per share by more than $0.02 in any given quarter in 2004.

(b) The difference between originally reported and reclassified basic and diluted earnings per share for income from continuing operations related to the sale of NAC (see Note 22). The earnings per share impact from the sale of NAC did not change earnings per share by more than $0.02 in any given quarter in 2003.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents are reasonable estimates of their fair values at December 31, 2004 and 2003 due to their short maturities.

We hold investments in debt securities for purposes other than trading. We believe that the carrying amounts of these investments represent reasonable estimates of their fair values at December 31, 2004 and 2003 due to the short-term reset of interest rates.

We also hold investments in fixed income and domestic equity securities for purposes other than trading. The December 31, 2004 and 2003 fair values of such investments, which we determine by using quoted market prices, approximate their carrying amount. For further information, see disclosure of cost and fair value of APS' nuclear decommissioning trust fund assets in Note 12.

On December 31, 2004, the carrying value of our long-term debt (excluding capitalized lease obligations) was $3.19 billion, with an estimated fair value of $3.30 billion. The carrying value of our long-term debt (excluding capitalized lease obligations) was $3.31 billion on December 31, 2003, with an estimated fair value of $3.46 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

15. EARNINGS PER SHARE

The following table presents earnings per weighted average common share outstanding for the years ended December 31, 2004, 2003 and 2002:

	2004	2003	2002
Basic earnings per share:			
Income from continuing operations	**$ 2.57**	$ 2.47	$ 2.79
Income (loss) from discontinued operations	**0.09**	0.17	(0.26)
Cumulative effect of change in accounting	**–**	–	(0.77)
Earnings per share – basic	**$ 2.66**	$ 2.64	$ 1.76
Diluted earnings per share:			
Income from continuing operations	**$ 2.57**	$ 2.47	$ 2.78
Income (loss) from discontinued operations	**0.09**	0.16	(0.25)
Cumulative effect of change in accounting	**–**	–	(0.77)
Earnings per share – diluted	**$ 2.66**	$ 2.63	$ 1.76

Dilutive stock options increased average common shares outstanding by approximately 135,000 shares in 2004, 140,000 shares in 2003 and 61,000 shares in 2002. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 91,532,473 shares in 2004, 91,405,134 shares in 2003 and 84,963,921 shares in 2002.

Options to purchase 1,058,616 shares of common stock were outstanding at December 31, 2004 but were not included in the computation of diluted earnings per share because the options’ exercise price was greater than the average market price of the common shares. Options to purchase shares of common stock that were not included in the computation of diluted earnings per share were 2,291,646 at December 31, 2003 and 1,629,958 at December 31, 2002.

16. STOCK-BASED COMPENSATION

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

In May 2002, shareholders approved the 2002 Long-Term Incentive Plan (2002 plan), which allows Pinnacle West to grant performance shares, stock ownership incentive awards and non-qualified and performance-accelerated stock options to key employees. The Company has reserved 6 million shares of common stock for issuance under the 2002 plan. No more than 1.8 million shares may be issued in relation to performance share awards and stock ownership incentive awards. The plan also provides for the granting of new non-qualified stock options at a price per share not less than the fair market value of the common stock at the time of grant. The stock options vest over three years, unless certain performance criteria are met, which can accelerate the vesting period. The term of the option cannot be longer than 10 years and the option cannot be repriced during its term.

The 1994 plan includes outstanding options but no new options will be granted under the plan. Options vested one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The 1994 plan also provided for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

In the third quarter of 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123. The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in APB No. 25.

In addition, see Note 2 for discussion of a new standard on share based payments (SFAS No. 123R).

Total stock-based compensation cost, including restricted stock, performance shares, stock options, and stock ownership incentives was $8 million in 2004, $6 million in 2003 and $5 million in 2002 for Pinnacle West, and $6 million in 2004, $3 million in 2003 and $3 million in 2002 for APS.

The following table is a summary of the status of outstanding stock options under our equity incentive plans as of December 31, 2004, 2003 and 2002 and changes during the years ending on those dates:

	2004 Shares	**2004** Weighted Average Exercise Price	2003 Shares	2003 Weighted Average Exercise Price	2002 Shares	2002 Weighted Average Exercise Price
Outstanding at beginning of year	**2,698,246**	**$ 38.56**	2,185,129	$ 39.96	1,832,725	$ 39.52
Granted	**37,580**	**37.85**	621,875	32.29	603,900	38.37
Exercised	**(372,205)**	**34.02**	(62,366)	26.09	(163,381)	28.25
Forfeited	**(87,498)**	**42.31**	(46,392)	37.61	(88,115)	41.54
Outstanding at end of year	**2,276,123**	**39.14**	2,698,246	38.56	2,185,129	39.96
Options exercisable at year-end	**1,859,340**	**40.59**	1,787,622	40.35	1,155,357	39.66
Weighted average fair value of options granted during the year		**$ 3.53**		$ 7.37		$ 6.16

The following table summarizes information about our stock options at December 31, 2004:

Exercise Prices Per Share	Options Outstanding	Weighted-Average Exercise Price	Weighted Average Remaining Contract Life (Years)	Options Exercisable	Weighted-Average Exercise Price
$23.39 – 28.07	**4,750**	**$ 27.44**	**0.5**	**4,750**	**$ 27.44**
28.07 – 32.75	**515,344**	**32,24**	**7.8**	**129,706**	**32.10**
32.75 – 37.42	**138,863**	**34.72**	**4.4**	**138,863**	**34.72**
37.42 – 42.10	**693,482**	**38.83**	**5.9**	**662,337**	**38.87**
42.10 – 46.78	**923,684**	**43.95**	**5.4**	**923,684**	**43.95**
	2,276,123			**1,859,340**	

The following table is a summary of the amount and weighted-average grant date fair value of stock compensation awards granted, other than options, during the years ended December 31, 2004, 2003 and 2002:

	2004 Shares	**2004** Grant Price	2003 Shares	2003 Grant Price	2002 Shares	2002 Grant Price
Restricted stock	**4,000**	**$ 37.68(a)**	4,000	$ 32.20(a)	6,000	$ 38.84(a)
Performance share awards	**215,285**	**37.85(b)**	119,085	32.29(b)	115,975	38.37(b)
Stock ownership incentive awards	**9,015**	**40.29(c)**	–	–	–	–

(a) Restricted stock priced at the average of the high and low market price on the grant date.
(b) Performance shares priced at the closing market price on the grant date.
(c) Shares are based on estimated ownership of Pinnacle West common stock.

17. 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 (primarily electricity 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.

In 2004, our other segment includes a $35 million gain ($21 million after-tax) related to the sale of El Dorado's limited partnership interest in the Phoenix Suns. The other segment also includes activity related to APS Energy Services' non-commodity trading activities, as well as the parent company and other subsidiaries.

Financial data for the years ended December 31, 2004, 2003 and 2002 by business segments is provided as follows (dollars in millions):

	Business Segments for the Year Ended December 31, 2004				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	$ 2,035	$ 462	$ 360	$ 43	$ 2,900
Purchased power and fuel costs	568	382	–	–	950
Other operating expenses	685	34	290	34	1,043
Operating margin	782	46	70	9	907
Depreciation and amortization	384	11	6	–	401
Interest expense	169	8	2	–	179
Other expense/(income)	4	(2)	(5)	(34)	(37)
Pretax margin	225	29	67	43	364
Income taxes	74	11	27	17	129
Income from continuing operations	151	18	40	26	235
Income from discontinued operations – net of income taxes of $5 (see Note 22)	–	–	4	4	8
Net income	$ 151	$ 18	$ 44	$ 30	$ 243
Total assets	$ 8,674	$ 746	$ 454	$ 23	$ 9,897
Capital expenditures	$ 483	$ 34	$ 81	$ –	$ 598

	Business Segments for the Year Ended December 31, 2003				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	$ 1,978	$ 392	$ 362	$ 27	$ 2,759
Purchased power and fuel costs	517	345	–	–	862
Other operating expenses	625	34	306	23	988
Operating margin	836	13	56	4	909
Depreciation and amortization	428	1	6	–	435
Interest expense	172	–	2	1	175
Other expense/(income)	(4)	–	(25)	–	(29)
Pretax margin	240	12	73	3	328
Income taxes	70	3	28	1	102
Income from continuing operations	170	9	45	2	226
Income from discontinued operations – net of income taxes of $10 (see Note 22)	–	–	10	5	15
Net income	$ 170	$ 9	$ 55	$ 7	$ 241
Total assets	$ 8,373	$ 680	$ 439	$ 27	$ 9,519
Capital expenditures	$ 686	$ 9	$ 72	$ –	$ 767

	Business Segments for the Year Ended December 31, 2002				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	$ 1,890	$ 287	$ 201	$ 27	$ 2,405
Purchased power and fuel costs	377	155	–	–	532
Other operating expenses	659	34	185	22	900
Operating margin	854	98	16	5	973
Depreciation and amortization	416	2	4	–	422
Interest expense	141	–	2	–	143
Other expense/(income)	19	–	(7)	7	19
Pretax margin	278	96	17	(2)	389
Income taxes	108	38	7	(1)	152
Income (loss) from continuing operations	170	58	10	(1)	237
Income (loss) from discontinued operations – net of income taxes of $14 (see Note 22)	–	–	9	(31)	(22)
Cumulative effect of change in accounting for trading activities – net of income taxes of $43	–	(66)	–	–	(66)
Net income (loss)	$ 170	$ (8)	$ 19	$ (32)	$ 149
Capital expenditures	$ 893	$ 19	$ 72	$ –	$ 984

18. DERIVATIVE AND ENERGY TRADING ACCOUNTING

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal, emissions allowances and in interest rates. We manage risks associated with these market fluctuations by utilizing various instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge our exposure to changes in interest rates and to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. As of December 31, 2004, we hedged exposures to the price variability of the commodities for a maximum of eight years. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

We recognize all derivatives, except those which receive a scope exception, as either assets or liabilities on the balance sheet and measure those instruments at fair value in accordance with SFAS No. 133, as amended by SFAS No. 149. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business receive the normal purchase and sales exception and are accounted for under the accrual method of accounting. Changes in the fair value of derivative instruments are recognized periodically in income unless certain hedge criteria are met. 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)). 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. We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. We use fair value hedges to limit our exposure to changes in fair value of an asset or liability.

We assess hedge effectiveness both at inception and on a continuing basis. Hedge effectiveness is related to the degree to which the derivative contract and the hedged item are correlated. It is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. We exclude the time value of certain options from our assessment of hedge effectiveness. Any change in the fair value resulting from ineffectiveness, or the amount by which the derivative contract and the hedged commodity are not directly correlated, is recognized immediately in net income.

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

All gains and losses (realized and unrealized) on trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis. Trading contracts that do not meet the definition of a derivative are accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

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 net these book-outs, which reduces both revenues and purchased power and fuel costs in our Consolidated Statement of Income, but this does not impact our financial condition, net income or cash flows.

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

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts, and on January 1, 2003 for existing contracts, with early adoption permitted. We adopted the EITF 02-3 guidance for all contracts 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.

Cash Flow Hedges

The changes in the fair value of our hedged positions included in the Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002 are comprised of the following (dollars in thousands):

	2004	2003	2002
Gains/(losses) on the ineffective portion of derivatives qualifying for hedge accounting	**$ (1,568)**	$ 8,237	$ 9,763
Gains/(losses) from the change in options' time value excluded from measurement of effectiveness	**185**	181	(2,484)
Gains from the discontinuance of cash flow hedges	**1,137**	–	386

During the twelve months ending December 31, 2005, we estimate that a net gain of $44 million before income taxes will be reclassified from accumulated other comprehensive loss as an offset to the effect on earnings of market price changes for the related hedged transactions.

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

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

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

	December 31, 2004				
	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated electricity:					
Mark-to-market	**$ 45,220**	**$ 19,417**	**$ (19,191)**	**$ (12,000)**	**$ 33,446**
Options and margin account	**18,821**	**118**	**(8,879)**	**–**	**10,060**
Marketing and trading:					
Mark-to-market	**102,855**	**204,512**	**(68,008)**	**(132,683)**	**106,676**
Emission allowances – at cost and margin account	**–**	**294**	**(17,328)**	**(11,579)**	**(28,613)**
Total	**$ 166,896**	**$ 224,341**	**$ (113,406)**	**$ (156,262)**	**$ 121,569**

	December 31, 2003				
	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated electricity:					
Mark-to-market	$ 44,079	$ 5,900	$ (47,268)	$ (3,028)	$ (317)
Options	–	12,101	–	–	12,101
Marketing and trading:					
Mark-to-market	53,551	116,363	(37,023)	(63,398)	69,493
Emission allowances – at cost	–	4,582	(8,464)	(16,304)	(20,186)
Total	$ 97,630	$ 138,946	$ (92,755)	$ (82,730)	$ 61,091

Cash or other assets may be required to serve as collateral against our open positions on certain energy-related contracts. Collateral provided to counterparties is $1 million at December 31, 2004 and $1 million at December 31, 2003, and is included in other current assets on the Consolidated Balance Sheet. Collateral provided to us by counterparties is $18 million at December 31, 2004 and $12 million at December 31, 2003, and is included in other current liabilities on the Consolidated Balance Sheet.

Fair Value Hedges

On January 29, 2004, we entered into two fixed-for-floating interest rate swap transactions on our $300 million 6.4% Senior Notes. The purpose of these hedges is to protect against significant fluctuations in the fair value of our debt. Our interest rate swaps are considered to be fully effective with any resulting gains or losses on the derivative offset by a similar loss or gain amount on the underlying fair value of debt. The fair value of the interest rate swaps was $2.6 million at December 31, 2004 and is included in investments and other assets with the corresponding offset in long-term debt less current maturities on the Consolidated Balance Sheets.

Credit Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 35% of Pinnacle West's $391 million of risk management and trading assets as of December 31, 2004. Our risk management process assesses and monitors the financial exposure of these and all other counterparties. Despite the fact that the great majority of trading counter-parties are rated as investment grade by the credit rating agencies, including the counterparties noted above, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities, local distribution companies and financial institutions. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See Note 1 "Derivative Accounting" for a discussion of our credit valuation adjustment policy.

19. OTHER INCOME AND OTHER EXPENSE

The following table provides detail of other income and other expense for the years ended December 31, 2004, 2003 and 2002 (dollars in thousands):

	Year Ended December 31,		
	2004	2003	2002
Other income:			
Investment gains (a)	**$ 38,256**	$ 3,649	$ –
Interest income	**7,470**	4,412	4,332
SunCor non-operating income (b)	**4,458**	24,740	7,355
Asset sales	**3,026**	618	568
Miscellaneous	**779**	2,144	2,655
Total other income	**$ 53,989**	$ 35,563	$ 14,910
Other expense:			
Non-operating costs (c)	**$ (15,524)**	$ (14,959)	$ (12,958)
Asset sales	**(1,382)**	(1,522)	(6,472)
Investment losses (d)	**–**	–	(10,439)
Miscellaneous	**(4,604)**	(4,093)	(3,786)
Total other expense	**$ (21,510)**	$ (20,574)	$ (33,655)

(a) Primarily related to the gain on the sale of El Dorado's limited partnership interest in the Phoenix Suns in the second quarter of 2004 for $35 million ($21 million after tax).
(b) Primarily related to the sale at SunCor of a land interest and profit participation agreement in the fourth quarter of 2003 for $18 million. In 2002, SunCor received $2.5 million for the profit participation.
(c) As defined by the FERC, includes below-the-line non-operating utility costs (primarily community relations).
(d) Primarily related to El Dorado's investment losses in NAC prior to consolidation in the third quarter of 2002.

20. VARIABLE INTEREST ENTITIES

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.

21. GUARANTEES

We have issued parental guarantees and letters of credit and obtained surety bonds on behalf of our unregulated subsidiaries. Our parental guarantees related to Pinnacle West Energy consist of equipment and performance guarantees related to our generation construction program, and long-term service agreement guarantees for new power plants. Our credit support instruments enable APS Energy Services to offer commodity energy and energy-related products. Non-performance or payment under the original contract by our unregulated subsidiaries would require us to perform under the guarantee or surety bond. No liability is currently recorded on the Consolidated Balance Sheets related to Pinnacle West's guarantees on behalf of its subsidiaries. Our guarantees have no recourse or collateral provisions to allow us to recover amounts paid under the guarantee. The amounts and approximate terms of our guarantees and surety bonds for each subsidiary at December 31, 2004 are as follows (dollars in millions):

	Guarantees		Surety Bonds	
	Amount	Term (in years)	Amount	Term (in years)
Parental:				
Pinnacle West Energy	$ 25	1	$ –	–
APS Energy Services	46	1	51	1
Total	$ 71		$ 51	

At December 31, 2004, we had entered into approximately $39 million of letters of credit which support various transmission and construction agreements. These letters of credit expire in 2005 and 2006. We intend to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required. At December 31, 2004, Pinnacle West has approximately $3 million of letters of credit related to workers' compensation expiring in 2006.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2004, approximately $200 million of letters of credit were outstanding to support existing pollution control bonds of approximately $200 million. The letters of credit are available to fund the payment of principal and interest of such debt obligations. In July 2004, $150 million of these letters of credit were renewed for a three-year term and expire in 2007. The remainder expire in 2005. APS has also entered into approximately $102 million of letters of credit to support certain equity lessors in the Palo Verde sale leaseback transactions (see Note 9 for further details on the Palo Verde sale leaseback transactions). These letters of credit expire in 2005. Additionally, APS has approximately $5 million of letters of credit related to counterparty collateral requirements expiring in 2006. APS intends to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required.

We provide indemnifications relating to liabilities arising from or related to certain of our agreements. APS has provided indemnifications to the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnifications is likely.

22. DISCONTINUED OPERATIONS

The following table provides a summary of SunCor and NAC income (loss) from discontinued operations (after income taxes) for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
SunCor	**$ 4**	$ 10	$ 9
NAC	**4**	5	(31)
Total Income (loss) from discontinued operations	**$ 8**	$ 15	$ (22)

SunCor

Certain components of SunCor's real estate sales activities, which are included in the real estate segment, are required to be reported as discontinued operations on Pinnacle West's Consolidated Statements of Income in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Among other guidance, SFAS No. 144 prescribes accounting for discontinued operations and defines certain activities as discontinued operations.

In the second quarter of 2002, SunCor sold a retail center, but maintained a continuing involvement through a management contract. In the first quarter of 2003, this management contract was canceled. As a result, the after-tax gain of $6 million ($10 million pretax) recorded in operations in 2002 related to this property was reclassified as discontinued operations on our Consolidated Statements of Income. The income from discontinued operations in the year ended December 31, 2002 primarily reflects this sale.

In 2003, SunCor sold its water utility company, which resulted in an after-tax gain of $8 million ($14 million pretax). The amounts of the gain on the sale and operating income of the water utility company in 2003 and 2002 are classified as discontinued operations on Pinnacle West's Consolidated Statements of Income.

In the fourth quarter of 2003, SunCor sold a retail center, which resulted in an after-tax gain of $2 million ($3 million pretax). The gain on the sale and the operating income related to this property in 2003 are classified as discontinued operations on Pinnacle West's Consolidated Statements of Income. There were no prior-year operations related to this retail center.

In 2004, SunCor sold commercial property, which resulted in an after-tax gain of $1 million ($2 million pretax). The gain on the sale and the operating income related to this property in 2004 are classified as discontinued operations on Pinnacle West's Consolidated Statements of Income. There were no prior-year operations related to this property.

The following table provides SunCor's revenue and income before income taxes (including the gains on disposals as noted above) related to properties classified as discontinued operations on Pinnacle West's Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
Revenue	**$ 11**	$ 71	$ 35
Income before taxes	**6**	17	15

NAC

In July 2004, we entered into an agreement to sell our investment in NAC. The transaction closed on November 18, 2004 and resulted in a pre-tax gain of $4 million, which is classified as discontinued operations in 2004. El Dorado began consolidating the operations of NAC in the third quarter of 2002. All related revenues and expenses for NAC have been reclassified to discontinued operations for the years ended December 31, 2003 and 2002 on Pinnacle West's Consolidated Statements of Income.

The following table provides the revenue and income before taxes (including the gain on disposal as noted above) for El Dorado's investment in NAC that was classified as discontinued operations for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
Revenue	**$ 31**	$ 58	$ 35
Income (loss) before taxes	**7**	8	(50)

Percentage of Completion – NAC

Certain NAC contract revenues are accounted for under the percentage-of-completion method. Revenues are recognized based upon total costs incurred to date compared to total costs expected to be incurred for each contract. Revisions in contract revenue and cost estimates are reflected in the accounting period when known. Provisions are made for the full amounts of anticipated losses in the periods in which they are first determined. Changes in job performance, job conditions and estimated profitability, including those arising from contract penalty provisions and final contract settlements, may result in revisions to costs and income, and are recognized in the period in which revisions are determined. Profit incentives are included in revenues when their realization is reasonably assured.

Contract costs include all direct material and labor costs and those indirect costs related to contract performance, such as indirect labor, supplies, tools, repairs and depreciation costs. General and administrative costs are charged to expense as incurred.

Assets and Liabilities Related to Discontinued Operations

Due to the sale of NAC, all NAC assets and liabilities have been reclassified to assets and liabilities related to discontinued operations on the Consolidated Balance Sheets at December 31, 2003 and are provided in the following table (dollars in thousands):

	2003
Cash	$ 5,867
Customer and other receivables	11,066
Net property, plant and equipment	5,404
Other	728
Assets related to discontinued operations	$ 23,065
Accounts payable	$ 10,406
Long-term debt less current maturities	800
Other	5,221
Liabilities related to discontinued operations	$ 16,427

CERTIFICATIONS

On June 18, 2004, in accordance with Section 303A.12 of the Listed Company Manual, our Chief Executive Officer certified to the New York Stock Exchange that he was not aware of any violation by the Company of NYSE corporate governance listing standards as of such date. In addition, on March 16, 2005, our Chief Executive Officer and Chief Financial Officer each filed a certification under Section 302 of the Sarbanes-Oxley Act (regarding the quality of the Company's public disclosure) as exhibits of the Company's Annual Report on Form 10-K for fiscal year 2004.

BOARD OF DIRECTORS


1.


2.

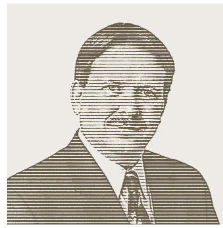

3.


4.


5.


6.


7.


8.


9.


10.


11.


12.

1. PAMELA GRANT (66) 1980* *Civic Leader* COMMITTEES: Audit; Corporate Governance; Human Resources 2. MARTHA O. HESSE (62) 1991 *Corporate Director* COMMITTEES: Audit, Chairman; Corporate Governance; Finance and Operating 3. THE REV. BILL JAMIESON, JR. (61) 1991 *President, Micah Institute, Asheville, North Carolina* COMMITTEES: Audit; Corporate Governance; Human Resources 4. ROY A. HERBERGER, JR. (62) 1992 *President Emeritus, Thunderbird, The Garvin School of International Management* COMMITTEES: Corporate Governance; Finance and Operating; Human Resources, Chairman 5. WILLIAM J. POST (54) 1994 *Chairman of the Board & Chief Executive Officer* COMMITTEE: Finance and Operating 6. HUMBERTO S. LOPEZ (59) 1995 *President, HSL Properties, Inc.* COMMITTEES: Audit; Corporate Governance; Human Resources 7. MICHAEL L. GALLAGHER (60) 1997 *Chairman Emeritus, Gallagher & Kennedy, P.A.* COMMITTEE: Finance and Operating, Chairman 8. BRUCE J. NORDSTROM (55) 1997 *Certified Public Accountant, Nordstrom and Associates, P.C.* COMMITTEES: Audit; Corporate Governance; Finance and Operating 9. JACK E. DAVIS (58) 1998 *President & Chief Operating Officer* COMMITTEE: Finance and Operating 10. WILLIAM L. STEWART (61) 1998 COMMITTEE: Finance and Operating 11. EDDIE BASHA (67) 1999 *Chairman of the Board, Bashas'* COMMITTEES: Audit; Corporate Governance; Human Resources 12. KATHRYN L. MUNRO (56) 1999 *Principal, BridgeWest L.L.C.* COMMITTEES: Audit; Corporate Governance, Chairman; Finance and Operating

** The year in which the individual first joined the Board of a Pinnacle West company.*

OFFICERS

Pinnacle West

William J. Post (54) 1973*
Chairman of the Board & Chief Executive Officer

Jack E. Davis (58) 1973
President & Chief Operating Officer

Donald E. Brandt (50) 2002
Executive Vice President & Chief Financial Officer

Robert S. Aiken (48) 1986
Vice President, Federal Affairs

Barbara M. Gomez (50) 1978
Vice President & Treasurer

Nancy C. Loftin (51) 1985
Vice President, General Counsel & Secretary

Martin L. Shultz (60) 1979
Vice President, Government Affairs

Arizona Public Service

William J. Post
Chairman of the Board

Jack E. Davis
President & Chief Executive Officer

Donald E. Brandt
Executive Vice President & Chief Financial Officer

Armando B. Flores (61) 1991
Executive Vice President, Corporate Business Services

James M. Levine (55) 1989
Executive Vice President, Generation

Steven M. Wheeler (56) 2001
Executive Vice President, Customer Service & Regulation

Gregg R. Overbeck (58) 1990
Senior Vice President, Nuclear Generation

Jan H. Bennett (57) 1967
Vice President, Customer Service

Ajit P. Bhatti (59) 1973
Vice President, Resource Planning

Dennis L. Brown (54) 1973
Vice President & Chief Information Officer

John R. Denman (62) 1964
Vice President, Fossil Generation

Edward Z. Fox (51) 1995
Vice President, Communications, Environment & Safety

Chris N. Froggatt (47) 1986
Vice President & Controller

Barbara M. Gomez
Vice President & Treasurer

David A. Hansen (45) 1980
Vice President, Power Marketing & Trading

Nancy C. Loftin
Vice President, General Counsel & Secretary

David Mauldin (55) 1990
Vice President, Nuclear Engineering & Support

Donald G. Robinson (51) 1978
Vice President, Planning

Pinnacle West Energy

James M. Levine
President & Chief Executive Officer

Donald E. Brandt
Chief Financial Officer

Ajoy K. Banerjee (59) 1999
Vice President, Construction & Operations

Warren C. Kotzmann (55) 1989
Vice President, Business & Corporate Services

SunCor Development

William J. Post
Chairman of the Board

John C. Ogden (59) 1972
Chief Executive Officer

Steven A. Betts (46) 2005
President

Duane S. Black (52) 1989
Executive Vice President & Chief Operating Officer

Jay T. Ellingson (56) 1992
Vice President, Development – Palm Valley

Margaret E. Kirch (55) 1988
Vice President, Commercial Development

Thomas A. Patrick (51) 1995
Vice President, Golf Operations

APS Energy Services

Vicki G. Sandler (48) 1982
President, APS Energy Services

El Dorado Investment

William J. Post
Chairman of the Board, President & Chief Executive Officer

** The year in which the individual was first employed within the Pinnacle West group of companies.*

SHAREHOLDER INFORMATION

Corporate Headquarters

400 North 5th Street
P.O. Box 53999
Phoenix, Arizona 85004
Main telephone number:
(602) 250-1000

Transfer Agent and Registrar

The Bank of New York
Receive and Deliver Department
P.O. Box 11002
Church Street Station
New York, NY 10286
(800) 457-2983
www.stockbny.com

Investor Relations Contacts

Rebecca L. Hickman,
Director, Investor Relations
Lisa Malagon, Manager
P.O. Box 53999 Station 9998
Phoenix, AZ 85072-3999
Telephone: (602) 250-5668
Fax: (602) 250-2789

Statistical Report

A detailed Statistical Report for Financial Analysis for 1999-2004 will be available in April on the Company's Web site or by writing to the Investor Relations Department.

www.pinnaclewest.com

Annual Meeting of Shareholders

Wednesday, May 18, 2005 at 10:30 a.m.
Hyatt Regency
122 North 2nd Street
Phoenix, AZ

Stock Listing

Ticker symbol: PNW on New York Stock Exchange and Pacific Stock Exchange
Newspaper financial listings: PinWst

Statewide Association for Utility Investors

The Arizona Utility Investors Association represents the interests of investors in Arizona utilities. If interested, send your name and address to:

Arizona Utility Investors Association
P.O. Box 34805
Phoenix, AZ 85067
(602) 257-9200
www.auia.org

Form 10-K

Pinnacle West's Annual Report to the Securities and Exchange Commission on Form 10-K will be available (after March 16, 2005) to shareholders upon written request, without charge. Write: Office of the Secretary.

Corporate Governance Report

To view the PInnacle West Corporate Governance Report please visit www.pinnaclewest.com.

Administrative Information

Company contact: (602) 250-5511
shareholderdept@pinnaclewest.com

Investors Advantage Plan and Shareholder Account Information

Pinnacle West offers a direct stock purchase plan. Any interested investor may purchase Pinnacle West common stock through the Investors Advantage Plan. Features of the Plan include a variety of options for reinvesting dividends, direct deposit of cash dividends, automatic monthly investment, certificate safekeeping and more. An Investors Advantage Plan prospectus and enrollment materials may be obtained by calling The Bank of New York at (800) 457-2983, at the Bank's Web site – www.stockbny.com or by writing to:

The Bank of New York
Shareholder Relations Department
P.O. Box 11258
Church Street Station
New York, NY 10286
(800) 457-2983

printed on recycled paper

Important notice to Shareholders:

Pinnacle West posts quarterly results and other important information on its Web site (www.pinnaclewest.com). If you would like to receive news by regular mail, fax or e-mail, let us know by mail or phone at the addresses and numbers listed on page 90. Also, let us know if you would like to be kept abreast of legislative and regulatory activities at the state and federal levels that could impact investor-owned utilities.

Design: Campbell Fisher Design www.thinkcfd.com

WWW.PINNACLEWEST.COM

PINNACLE WEST
CAPITAL CORPORATION