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. Pinnacle West Energy, which was formed in 1999, was the subsidiary through which we conducted our unregulated generation operations. See Note 3 for a discussion of the transfer of the PWEC Dedicated Assets from Pinnacle West Energy to APS. As of January 10, 2006, Pinnacle West Energy no longer owns any generating plants and has ceased 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, "Accounting for Derivative Instruments and Hedging Activities," as amended. 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)). To the extent the amounts that would otherwise be recognized in income are eligible to be recovered through the PSA, the amounts will be recorded as either a regulatory asset or liability and have no effect on earnings. SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard. 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.

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, 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, 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.

A major component of our regulatory assets is the retail fuel and power costs deferred under the PSA. APS defers for future rate recovery 90% of the difference between actual retail fuel and power costs and the amount of such costs currently included in base rates.

As part of a 1999 retail rate case settlement agreement, APS amortized certain regulatory assets over a period that ended June 30, 2004. Amortization was $18 million in 2004 and $86 million in 2003.

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

December 31,	**2005**	2004
Deferred fuel purchased power (Note 3)	**$173**	$ –
Competition rules compliance charge	**42**	50
Deferred compensation	**25**	24
Regulatory asset for deferred income taxes	**19**	12
Loss on reacquired debt (a)	**18**	17
Capital contributions on the Mead-Phoenix transmission line	**14**	13
Coal reclamation	**13**	–
Bark beetle remediation	**6**	–
Spent nuclear fuel storage (Note 11)	**6**	11
Other	**8**	8
Total regulatory assets	**$324**	$135

(a) See "Reacquired Debt Costs" below.

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

December 31,	**2005**	2004
Removal costs (a)	**$385**	$376
Regulatory liability related to asset retirement obligations	**101**	86
Deferred fuel and purchased power – mark-to-market	**31**	–
Regulatory liability for deferred income taxes	**24**	–
Deferred interest income	**22**	22
Deferred gains on utility property	**20**	20
Demand-side management	**7**	–
Other	**2**	3
Total regulatory liabilities	**$592**	$507

(a) In accordance with SFAS No. 71, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal.

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. Liabilities associated with the retirement of tangible long-lived assets are 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 "Accounting for Asset Obligations," as interpreted by FIN 47. APS believes it can recover in regulated rates the 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, 2005 were as follows:

- Fossil plant – 19 years;
- Nuclear plant – 20 years;
- Other generation – 28 years;
- Transmission – 40 years;
- Distribution – 32 years; and
- Other – 6 years.

For the years 2003 through 2005, the depreciation rates ranged from a low of 1.2% to a high of 11.43%. The weighted-average rate was 3.0% for 2005, 3.36% for 2004 and 3.35% for 2003. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 34 years. See "APS 2003 Rate Case" in Note 3 for a discussion of changes in depreciation rates.

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 are reviewed in accordance with EITF 03-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments."

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance non-regulated construction projects. The rate used to calculate capitalized interest was a composite rate of 5.7% for 2005, 4.9% for 2004 and 4.7% for 2003. 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. APS' allowance for borrowed funds is included in capitalized interest on the Consolidated Financial Statements. 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 7.7% for 2005, 8.4% for 2004 and 8.6% for 2003. APS compounds AFUDC monthly and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

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. Beginning April 2005 in accordance with the order in the APS 2003 Rate Case, we exclude city franchise fees from both electric revenues and operating expenses.

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. 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 addition, see Note 22 – Discontinued Operations.

Cash and Cash Equivalents

We consider all highly liquid investments 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 investment in debt securities on our Consolidated Balance Sheets.

We have changed the presentation of our nuclear decommissioning trust investment in our Consolidated Statements of Cash Flows for the year ended December 31, 2005, to present investing cash outflows separately from investing cash inflows. Investing cash inflows and outflows in the nuclear decommissioning trust investment amounts were previously presented in Other within the investing section of the Consolidated Statements of Cash Flows. In addition, we changed the presentation of prior year amounts in order to be consistent with the 2005 presentation. There was no impact to net cash provided by (used in) operating, investing or financing activities as a result of this change in presentation.

During 2005, we revised the presentation of our Consolidated Statements of Cash Flows to include the cash flows from discontinued operations within the categories of operating, investing, and financing activities. A summary of the effects of the change in presentation on the Consolidated Statements of Cash Flows for the years ended December 31, 2004 and 2003, is as follows (dollars in millions):

Year Ended December 31,	2004	2003
Net cash flows from operating activities as previously reported	$ 842	$ 901
Change in net cash flows from discontinued operations	9	1
Net cash flows from operating activities as currently reported	$ 851	$ 902
Net cash flows used for investing activities as previously reported	$(532)	$(815)
Change in net cash flows used for discontinued operations	(13)	6
Net cash flows used for investing activities as currently reported	$(545)	$(809)
Net cash flows used for financing activities as previously reported	$(278)	$ (32)
Change in net cash flows used for discontinued operations	(2)	(2)
Net cash flows used for financing activities as currently reported	$(280)	$ (34)

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

APS defers gains and losses incurred upon early retirement of debt. These costs are amortized equally on a monthly basis over the remaining life of the original debt consistent with its ratemaking treatment.

Stock-Based Compensation

We apply 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." In addition, SFAS No. 123R is effective for us as of January 1, 2006. We have evaluated the impacts of this new guidance and do not believe it will have a material impact on our financial statements.

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 2005 (dollars in thousands, except per share amounts):

	2005	2004	2003
Net Income as reported:	**$176,267**	$243,195	$240,579
Add: Stock compensation expense included in reported net income (net of tax)	**3,738**	4,690	3,514
Deduct: Total stock compensation expense determined under fair value method (net of tax)	**(3,738)**	(5,311)	(5,220)
Pro forma net income	**$176,267**	$242,574	$238,873
Earnings per share – basic:			
As reported	**$ 1.83**	$ 2.66	$ 2.64
Pro forma (fair value method)	**$ 1.83**	$ 2.65	$ 2.62
Earnings per share – diluted:			
As reported	**$ 1.82**	$ 2.66	$ 2.63
Pro forma (fair value method)	**$ 1.82**	$ 2.65	$ 2.61

In order to calculate the fair value of the 2004 and 2003 stock option grants (no stock options were granted in 2005) and the pro forma information above, we calculated the fair value of each stock option granted under the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated as of the date the option was granted. The following weighted-average assumptions were used to calculate the fair value of the stock options:

	2004	2003
Risk-free interest rate	3.15%	3.35%
Dividend yield	4.76%	5.26%
Volatility	17.04%	38.03%
Expected life (months)	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, primarily software, 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 $33 million in 2005, $34 million in 2004, and $25 million in 2003. Estimated amortization expense on existing intangible assets over the next five years is $31 million in 2006, $25 million in 2007, $14 million in 2008, $4 million in 2009, and $3 million in 2010. At December 31, 2005, the weighted average remaining amortization period for intangible assets is 3 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. In 2002, we began accounting for stock-based compensation using the fair value method. We adopted SFAS No. 123R on January 1, 2006. We believe the impacts of this new guidance on our financial statements will be immaterial.

Effective December 31, 2005, we adopted FIN 47, "Accounting for Conditional Asset Retirement Obligations – an interpretation of FASB Statement No. 143." FIN 47 clarifies that an entity must record a liability for the fair value of an asset retirement obligation for which the timing and/or method of settlement are conditional on a future event if the liability's fair value can be reasonably estimated. We have evaluated our asset retirement obligations under this new guidance and determined that no additional liabilities need to be recorded at this time.

3. REGULATORY MATTERS

APS General Rate Case

On January 31, 2006, APS filed with the ACC updated financial schedules, testimony and other data in the general rate case that APS originally filed on November 4, 2005. As requested by the ACC staff, the updated information uses the twelve months ended September 30, 2005 as the test period instead of the test year ended December 31, 2004 used in APS' original filing. As a result of the updated filing, APS is requesting a 21.3%, or $453.9 million, increase in its annual retail electricity revenues effective no later than December 31, 2006. The original filing requested a 19.9%, or $409.1 million, retail rate increase.

The updated requested rate increase is designed to recover the following (dollars in millions):

	Updated Filing (January 31, 2006)		Original Filing (November 4, 2005)	
	Annual Revenue Increase	Percentage Increase	Annual Revenue Increase	Percentage Increase
Increased fuel and purchased power	$299.0	14.0%	$246.8	12.0%
Capital structure update	98.3	4.6%	96.8	4.7%
Rate base update, including acquisition of Sundance Plant	46.2	2.2%	42.5	2.1%
Pension Funding	41.3	1.9%	41.2	2.0%
Other items	(30.9)	(1.4)%	(18.2)	(0.9)%
Total increase	$453.9	21.3%	$409.1	19.9%

The request is based on (a) a rate base of $4.4 billion, which approximates the ACC-jurisdictional portion of the book value of utility plant, net of accumulated depreciation, as of September 30, 2005; (b) a base rate for fuel and purchased power costs of $0.031904 per kilowatt-hour based on estimated 2006 prices; and (c) a proposed capital structure of 45% long-term debt and 55% common stock equity, with a weighted-average cost of capital of 8.73% (5.41% for long-term debt and 11.50% for common stock equity). The requested increase in annual retail electricity revenues from the original filing is based solely on increased fuel and purchased power costs, slightly offset by other items (see the above chart). If the ACC approves the requested base rate increase for fuel and purchased power costs (see clause (b) of this paragraph), subsequent PSA rate adjustments and/or PSA surcharges would be reduced because such costs would otherwise be eligible for recovery in the future under APS' PSA.

The updated request does not include the PSA annual adjustor rate increase of approximately 5% that took effect February 1, 2006 or the application for two separate PSA surcharges that APS filed on February 2, 2006. See "Power Supply Adjustor" below.

Application for Emergency Interim Rate Increase

On January 6, 2006, APS filed with the ACC an application requesting an emergency interim rate increase of $299 million, or approximately 14%, to be effective April 1, 2006. The purpose of the emergency interim rate increase is solely to address APS' under-collection of higher annual fuel and purchased power costs. The increase would accelerate recovery of the fuel and purchased power component of APS' general rate case and is not an additional increase and would be subject to refund. On February 28, 2006, several parties filed direct testimony in this matter. The ACC staff and the Residential Utility Consumer Office each recommended that the ACC deny APS' request for emergency rate relief, and each cited the ACC's January 25, 2006 modification of the PSA as a basis for its recommendation (see "Power Supply Adjustor" below). Because "concern continues to exist regarding the build-up of deferred fuel balances in 2006 and the uncertain time frame for recovery of prudently incurred fuel and purchased power costs," the ACC staff also recommended, among other things, that the ACC allow APS to file for PSA surcharge requests in 2006 on a quarterly basis, with the first request to be filed no earlier than June 30, 2006. A business coalition that advocates on behalf of retail electric customers in Arizona and a major APS customer filed joint testimony recommending that the ACC approve an interim rate increase of $126 million in calendar-year 2006. Hearings on the emergency interim rate increase request are scheduled to begin on March 20, 2006. We cannot predict the outcome of this matter.

Power Supply Adjustor

PSA PROVISIONS

The PSA approved by the ACC in April 2005 as part of APS' 2003 rate case provides for adjustment of retail rates to reflect variations in retail fuel and purchased power costs. On January 25, 2006, the ACC modified the PSA in certain respects. The PSA, as modified, is subject to specified parameters and procedures, including the following:

- APS will record deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the base fuel amount (currently $0.020743 per kWh);
- the deferrals are subject to a 90/10 sharing arrangement in which APS must absorb 10% of the retail fuel and purchased power costs above the base fuel amount and may retain 10% of the benefit from the retail fuel and purchased power costs that are below the base fuel amount;
- amounts to be recovered or refunded through the annual PSA adjustment are limited to a cumulative plus or minus $0.004 per kWh over the life of the PSA;
- the recoverable amount of annual retail fuel and purchased power costs through current base rates and the PSA was originally capped at $776.2 million; however, the ACC has removed the cap pending the ACC's final ruling on APS' pending request to have the cap eliminated or substantially raised;
- the PSA will remain in effect for a minimum five-year period, but the ACC may eliminate the PSA at any time, if appropriate, in the event APS files a rate case before the expiration of the five-year period (which APS did by filing the general rate case noted above) or if APS does not comply with the terms of the PSA; and
- APS is prohibited from requesting PSA surcharges until after the PSA annual adjustor rate has been set each year. The amount available for potential PSA surcharges will be limited to the amount of accumulated deferrals through the prior year-end which are not expected to be recovered through the annual adjustor or any PSA surcharges previously approved by the ACC.

2006 PSA ANNUAL ADJUSTOR The effective date of the PSA's annual adjustor is February 1, and the adjustor rate was set at the maximum $0.004 per kilowatt-hour effective February 1, 2006. The change in the adjustor rate represents a retail rate increase of approximately 5% designed to recover $110 million of deferred fuel and purchased power costs over the twelve-month period beginning February 1, 2006.

APPLICATION FOR PSA SURCHARGES On February 2, 2006, APS filed with the ACC an application for two separate surcharges under the PSA. The surcharges would recover approximately $60 million in retail fuel and purchased power costs deferred by APS in 2005 under the PSA. The combined surcharges would represent a temporary rate increase of approximately 2.6% during the overlapping portion of the twelve-month recovery periods for the two surcharges. The other component of the 2005 PSA deferrals is being recovered under the 2006 PSA annual adjustor discussed in the preceding paragraph. The first surcharge would recover approximately $15 million over a twelve-month period, representing a temporary rate increase of approximately 0.66%, proposed to begin with the date of the ACC's decision in APS' pending emergency interim rate case. The second requested surcharge would recover approximately $45 million over a twelve-month period, representing a temporary rate increase of approximately 1.9%, proposed to begin no later than the ACC's completion of its inquiry regarding the unplanned 2005 Palo Verde outages. The $45 million of PSA deferrals represents replacement power costs associated with these outages.

PROPOSED MODIFICATIONS TO PSA (REQUESTED IN GENERAL RATE CASE)

In its pending general rate case, APS has requested the following modifications to the PSA:

- The $0.004 per kWh maximum adjustor rate over the life of the PSA would be eliminated, while the $0.004 per kWh maximum annual change in the adjustor rate would remain in effect;
- The $776.2 million annual limit on the retail fuel and purchased power costs under APS' current base rates and the PSA would be removed or increased (although APS may defer fuel and purchased power costs above $776.2 million per year pending the ACC's final ruling on APS' pending request to have the cap eliminated or substantially raised);
- The current provision that APS is required to file a surcharge application with the ACC after accumulated pretax PSA deferrals equal $50 million and before they equal $100 million would be eliminated, thereby giving APS flexibility in determining when a surcharge filing should be made;
- The costs of renewable energy and capacity costs attributable to purchased power obtained through competitive procurement would be excluded from the existing 90/10 sharing arrangement under which APS absorbs 10% of the retail fuel and purchased power costs above the base fuel amount and retains 10% of the benefit from retail fuel and purchased power costs that are below the base fuel amount; and
- 10% of any realized gains or losses resulting from APS' hedges of Retail Fuel and Power Costs would be retained or absorbed by APS before being subject to the 90/10 sharing provision under the PSA.

APS 2003 Rate Case

On April 7, 2005, the ACC issued an order in the rate case that APS filed on June 27, 2003. In addition to the ACC's approval of the PSA discussed under "Power Supply Adjustor" above, certain key financial components of the order include:

- APS received an annual retail rate increase of approximately 4.2%, which was effective as of April 1, 2005. This increase does not include the impact of the PSA.
- APS was authorized to acquire the PWEC Dedicated Assets from Pinnacle West Energy, with a net carrying value of approximately $850 million, and to rate base the PWEC Dedicated Assets at a rate base value of $700 million, which resulted in a mandatory rate base disallowance of approximately $150 million. Due to depreciation and other miscellaneous factors, the actual disallowance was $139 million at December 31, 2005. This transfer was completed on July 29, 2005. As a result, for financial reporting purposes, APS recognized a one-time, after-tax net plant regulatory disallowance of approximately $84 million in 2005.
- Effective April 1, 2005, APS adopted longer service lives for certain depreciable assets. This change is expected to have the effect of reducing annual depreciation expense for financial reporting purposes by approximately $30 million. APS also adopted longer service lives for the PWEC Dedicated Assets, which is expected to have the effect of reducing annual depreciation expense for financial reporting purposes by approximately $10 million.

Equity Infusions

On November 8, 2005, the ACC approved Pinnacle West's request to infuse more than $450 million of equity into APS during 2005 or 2006. These infusions consist of about $250 million of the proceeds of Pinnacle West's common equity issuance on May 2, 2005 and about $210 million of the proceeds from the sale of Silverhawk in January 2006 (see Note 22). Pinnacle West has made these equity infusions into APS.

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.

4. INCOME TAXES

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements purposes. 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 and again in 2005, 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 or results of operations. We expect that it will have a negative impact on cash flows.

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,	**2005**	2004	2003
Current:			
Federal	**$ 107,837**	$ 200,133	$ 22,875
State	**13,064**	48,054	3,752
Total current	**120,901**	248,187	26,627
Deferred:			
Income from continuing operations	**11,930**	(113,850)	81,756
Discontinued operations	**(35,736)**	–	3,706
Total deferred	**(23,806)**	(113,850)	85,462
Total income tax expense	**97,095**	134,337	112,089
Less: income tax expense (benefit) on discontinued operations	**(29,797)**	(1,805)	9,887
Income tax expense – continuing operations	**$ 126,892**	$ 136,142	$ 102,202

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

Year Ended December 31,	**2005**	2004	2003
Federal income tax expense at 35% statutory rate	**$ 122,519**	$ 133,956	$ 114,655
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	**11,981**	14,460	11,493
Credits and favorable adjustments related to prior years resolved in current year	–	(6,138)	(17,944)
Medicare Subsidy Part-D (see Note 8)	**(2,733)**	(1,778)	–
Allowance for equity funds used during construction (see Note 1)	**(3,694)**	(1,547)	(4,984)
Other	**(1,181)**	(2,811)	(1,018)
Income tax expense – continuing operations	**$ 126,892**	$ 136,142	$ 102,202

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

December 31,	**2005**	2004
Current liability	**$ (94,710)**	$ (9,057)
Long term liability	**(1,225,253)**	(1,227,553)
Accumulated deferred income taxes – net	**$ (1,319,963)**	$ (1,236,610)

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

December 31,	**2005**	2004
DEFERRED TAX ASSETS		
Risk management and trading activities	**$ 323,696**	$ 91,021
Regulatory liabilities:		
Asset retirement obligation	**189,726**	182,086
Federal excess deferred income taxes	**14,446**	16,341
Deferred fuel and purchased power – mark-to-market	**11,923**	–
Other	**29,720**	8,282
Pension liability	**83,753**	91,973
Deferred gain on Palo Verde Unit 2 sale leaseback	**17,868**	19,816
Other	**91,015**	70,849
Total deferred tax assets	**762,147**	480,368
DEFERRED TAX LIABILITIES		
Plant-related	**(1,426,158)**	(1,516,174)
Risk management and trading activities	**(524,940)**	(146,037)
Regulatory assets:		
Deferred fuel and purchased power	**(67,461)**	–
Other	**(63,551)**	(54,767)
Total deferred tax liabilities	**(2,082,110)**	(1,716,978)
Accumulated deferred income taxes – net	**$ (1,319,963)**	$ (1,236,610)

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

Pinnacle West had committed lines of credit of $300 million at December 31, 2005 and December 31, 2004, 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 December 2010. Pinnacle West had no outstanding borrowings at December 31, 2005 and December 31, 2004. Pinnacle West had approximately $11 million of letters of credit issued under the line at December 31, 2005 ($7 million of which terminated as a result of the sale of Silverhawk – see Note 22) and approximately $13 million of letters of credit issued under the line at December 31, 2004. The commitment fees were 0.15% in 2005 and 0.175% in 2004. Pinnacle West had no commercial paper borrowings outstanding at December 31, 2005 and 2004. All Pinnacle West and APS bank lines of credit and commercial paper agreements are unsecured.

APS had committed lines of credit with various banks of $400 million at December 31, 2005 and $325 million at December 31, 2004, which were available either to support the issuance of up to $250 million in commercial paper or to be used for bank borrowings, including the issuance of letters of credit. The current line matures in December 2010. The commitment fees at December 31, 2005 and 2004 for these lines of credit were 0.11% and 0.15% per annum. APS had no bank borrowings outstanding under these lines of credit at December 31, 2005 and 2004. APS had approximately $4.8 million of letters of credit issued under the line at December 31, 2005.

APS had no commercial paper borrowings outstanding at December 31, 2005 and 2004. By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

SunCor had revolving lines of credit totaling $150 million at December 31, 2005 and $90 million at December 31, 2004. The commitment fees were 0.125% in 2005 and 2004. SunCor had $123 million outstanding at December 31, 2005 and $35 million outstanding at December 31, 2004. The weighted-average interest rate was 5.93% at December 31, 2005 and 4.50% at December 31, 2004. Interest was based on LIBOR plus 1.5% for 2005 and LIBOR plus 2% or prime plus 0.5% for 2004. The balance is included in long-term debt on the Consolidated Balance Sheets at December 31, 2005 and it was in short-term debt on the Consolidated Balance Sheets at December 31, 2004. SunCor had other short-term loans in the amount of $16 million at December 31, 2005 and $36 million at December 31, 2004. These loans are made up of multiple notes primarily with variable interest rates based on LIBOR plus 2.25% and 2.50% or prime plus 1.75% at December 31, 2005 and LIBOR plus 2.5% at December 31, 2004.

6. LONG-TERM DEBT

Substantially all of APS' debt is unsecured. 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, 2005 and 2004 (dollars in thousands):

			December 31,	
	Maturity Dates (a)	Interest Rates	**2005**	2004
APS				
Pollution control bonds (b)	2024-2034	(c)	**$ 565,855**	$ 565,860
Pollution control bonds with senior notes	2029	5.05%	**90,000**	90,000
Unsecured notes (d)	2005	6.25%	**–**	100,000
Unsecured notes (e)	2005	7.625%	**–**	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 (e)	2014	5.80%	**300,000**	300,000
Secured note	2014	6.00%	**1,745**	1,900
Senior notes	2006	6.75%	**83,695**	83,695
Senior notes (f)	2035	5.50%	**250,000**	–
Unamortized discount and premium			**(9,151)**	(7,968)
Capitalized lease obligations	2006-2012	(g)	**8,179**	9,854
Subtotal			**2,565,323**	2,718,341
SUNCOR				
Notes payable	2006-2008	(h)	**129,040**	15,467
Capitalized lease obligations	2005-2007	8.91%	**266**	507
Subtotal			**129,306**	15,974
PINNACLE WEST				
Senior notes (i)	2006	6.40%	**298,518**	302,589
Unamortized discount and premium			**(29)**	(143)
Floating rate senior notes	2005	(j)	**–**	165,000
Capitalized lease obligations	2005-2007	5.45%	**284**	389
Subtotal			**298,773**	467,835
Total long-term debt			**2,993,402**	3,202,150
Less current maturities			**384,947**	617,165
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			**$2,608,455**	$2,584,985

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.
(b) On March 1, 2005, Maricopa County Arizona Pollution Control Corporation issued $164 million of variable interest rate pollution control bonds, 2005 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.
(c) The weighted-average rate was 3.25% at December 31, 2005 and 1.89% at December 31, 2004. Changes in short-term interest rates would affect the costs associated with this debt.
(d) On January 15, 2005, APS repaid its $100 million 6.25% notes due 2005. APS used cash on hand to repay these notes.
(e) On August 1, 2005, APS repaid $300 million of its 7.625% notes due 2005. APS used cash from the issuance of $300 million 5.8% senior unsecured notes due June 30, 2014.
(f) On August 22, 2005, APS issued $250 million of 5.50% senior notes due 2035. A portion of the proceeds from the sale of the notes was used for general corporate purposes and, on October 3, 2005, the balance of the proceeds, along with cash on hand, was used to fund the $500 million that APS was obligated to transfer to Pinnacle West Energy in connection with APS' acquisition of the PWEC Dedicated Assets.
(g) The weighted-average rate was 5.81% at December 31, 2005 and 5.78% at December 31, 2004. Capital leases are included in property, plant and equipment on the Consolidated Balance Sheets for both December 31, 2005 and December 31, 2004.
(h) SunCor had $123 million outstanding at December 31, 2005 under its revolving line of credit. The weighted-average interest rate was 5.93% at December 31, 2005. The remaining amount of approximately $6 million at December 31, 2005 was made up of multiple notes with variable interest rates based on the lenders' prime rates plus 0.25% or LIBOR plus 2.00%. There is also a note at a fixed rate of 4.25%.
(i) On January 29, 2004, we entered into a fixed-for-floating interest rate swap transaction related to the $300 million 6.40% senior note. The transaction qualifies as a fair value hedge under SFAS No. 133.
(j) The weighted-average rate was 2.06% at December 31, 2004.

On February 28, 2006, Pinnacle West entered into an Uncommitted Master Shelf Agreement with Prudential Investment Management, Inc. ("Prudential") and certain of its affiliates. The agreement provides the terms under which Pinnacle West may offer up to $200 million of its senior notes for purchase by Prudential affiliates at any time prior to December 31, 2007. The maturity of notes issued under the agreement cannot exceed five years. Pursuant to the agreement, on February 28, 2006, Pinnacle West issued and sold to Prudential affiliates $175 million aggregate principal amount of its 5.91% Senior Notes, Series A, due February 28, 2011 (the "Series A Notes"). Pinnacle West will use the proceeds of the Series A Notes to repay at maturity a portion of the $300 million aggregate principal amount of its 6.40% Senior Notes due April 1, 2006 or for other general corporate purposes.

Pinnacle West's and APS' debt covenants related to their respective bank financing arrangements include a debt to capitalization ratio. Certain of APS' bank financing arrangements also include 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. For each of Pinnacle West and APS, these covenants require that the ratio of consolidated debt to total consolidated capitalization cannot exceed 65%. At December 31, 2005, the ratio was approximately 49% for Pinnacle West and 47% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for APS. The interest coverage is approximately 4 times under APS' bank financing agreements as of December 31, 2005. 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 and could cross-default other debt.

Neither Pinnacle West's nor APS' financing agreements contain "rating triggers" that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, in the event of a further rating 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 certain other material 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 certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for revolver borrowings.

The following table shows principal payments due on Pinnacle West's and APS' total long-term debt and capitalized lease requirements (dollars in millions):

Year	Pinnacle West	APS
2006	$ 387	$ 86
2007	1	1
2008	129	1
2009	1	1
2010	224	224
Thereafter	2,261	2,261

7. COMMON STOCK AND TREASURY STOCK

Our common stock and treasury stock activity during each of the three years 2005, 2004 and 2003 is as follows (dollars in thousands):

	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount
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)
Common stock issuance (a)	**7,274,272**	**298,330**	**–**	**–**
Purchase of treasury stock (b)	**–**	**–**	**(28,124)**	**(1,601)**
Reissuance of treasury stock for stock compensation (net)	**–**	**–**	**17,588**	**784**
Other	**–**	**–**	**–**	**–**
Balance at December 31, 2005	**99,077,133**	**$ 2,067,377**	**(20,058)**	**$ (1,245)**

(a) On May 2, 2005, Pinnacle West issued 6,095,000 shares of its common stock at an offering price of $42 per share, resulting in net proceeds of approximately $248 million. Pinnacle West used the net proceeds for general corporate purposes, including making capital contributions to APS, which, in turn, used such funds to pay a portion of the approximately $190 million purchase price to acquire the Sundance Plant and for other capital expenditures incurred to meet the growing needs of APS' service territory.

(b) Represents shares of common stock withheld from certain stock awards for tax purposes.

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 its 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 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. The market-related value of our plan assets is their fair value at the measurement date.

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. Pinnacle West adopted FSP 106-2 retroactive to the beginning of 2004. The effect of this was to reduce the accumulated postretirement benefit obligation (APBO) at January 1, 2004 by $66 million, and net periodic cost for 2004 by $11 million, as compared with the amount calculated without considering the effects of the subsidy.

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		
	2005	2004	2003	**2005**	2004	2003
Service cost – benefits earned during the period	**$ 45,027**	$ 41,207	$ 37,662	**$ 20,913**	$ 17,557	$ 15,858
Interest cost on benefit obligation	**87,189**	81,873	76,951	**34,223**	29,488	30,163
Expected return on plan assets	**(88,403)**	(78,790)	(65,046)	**(30,471)**	(24,773)	(18,762)
Amortization of:						
Transition (asset) obligation	**(3,227)**	(3,227)	(3,227)	**3,005**	3,005	3,005
Prior service cost (credit)	**2,401**	2,401	2,401	**(125)**	(125)	(125)
Net actuarial loss	**19,810**	17,946	18,135	**9,243**	7,414	9,714
Net periodic benefit cost	**$ 62,797**	$ 61,410	$ 66,876	**$ 36,788**	$ 32,566	$ 39,853
Portion of cost charged to expense	**$ 26,375**	$ 25,792	$ 30,094	**$ 15,451**	$ 13,678	$ 17,934
APS share of costs charged to expense	**$ 24,169**	$ 22,483	$ 25,450	**$ 14,159**	$ 11,923	$ 15,166

The following table shows the plans' changes in the benefit obligations for the years 2005 and 2004 (dollars in thousands):

	Pension		Other Benefits	
	2005	2004	**2005**	2004
Benefit obligation at January 1	**$1,454,244**	$1,307,628	**$ 536,213**	$ 540,181
Service cost	**45,027**	41,207	**20,913**	17,557
Interest cost	**87,189**	81,873	**34,223**	29,488
Benefit payments	**(46,109)**	(45,195)	**(16,962)**	(14,332)
Actuarial losses (gains)	**55,717**	68,731	**11,291**	(36,681)
Benefit obligation at December 31	**$1,596,068**	$1,454,244	**$ 585,678**	$ 536,213

The following table shows the qualified pension plan and other benefit plan changes in the fair value of plan assets for the years 2005 and 2004 (dollars in thousands):

	Pension		Other Benefits	
	2005	2004	**2005**	2004
Fair value of plan assets at January 1	**$ 982,282**	$ 887,311	**$ 352,084**	$ 294,051
Actual return on plan assets	**73,298**	102,829	**27,302**	32,433
Employer contributions	**52,700**	35,000	**36,788**	32,600
Benefit payments	**(43,432)**	(42,858)	**–**	(7,000)
Fair value of plan assets at December 31	**$1,064,848**	$ 982,282	**$ 416,174**	$ 352,084

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, 2005 and 2004 (dollars in thousands):

	Pension		Other Benefits	
	2005	2004	**2005**	2004
Funded status at December 31	**$ (531,220)**	$ (471,962)	**$ (169,504)**	$ (184,129)
Unrecognized net transition (asset) obligation	**(645)**	(3,873)	**21,034**	24,039
Unrecognized prior service cost (credit)	**11,833**	14,234	**(1,296)**	(1,422)
Unrecognized net actuarial losses	**426,991**	375,980	**170,011**	158,271
Benefit (liability) asset recognized in the Consolidated Balance Sheets	**$ (93,041)**	$ (85,621)	**$ 20,245**	$ (3,241)

The following table shows the projected benefit obligation and the accumulated benefit obligation for pension plans in excess of plan assets as of December 31, 2005 and 2004 (dollars in thousands):

	2005	2004
Projected benefit obligation	**$ 1,596,068**	$1,454,244
Accumulated benefit obligation	**$ 1,329,324**	$1,216,727
Less fair value of plan assets	**1,064,848**	982,282
Pinnacle West pension liability	**$ 264,476**	$ 234,445
APS share of pension liability	**$ 233,342**	$ 203,668

The following table shows the details related to benefits included on the Consolidated Balance Sheets as of December 31, 2005 and 2004 (dollars in thousands):

	Pension		Other Benefits	
	2005	2004	**2005**	2004
(Accrued) prepaid benefit cost	**$ (93,041)**	$(85,621)	**$ 20,245**	$(3,241)
Additional minimum liability	**(171,435)**	(148,824)	**–**	–
Total (liability) asset	**(264,476)**	(234,445)	**20,245**	(3,241)
Intangible asset	**11,833**	14,234	**–**	–
Accumulated other comprehensive loss (pretax)	**159,602**	134,590	**–**	–
Net amount recognized	**$ (93,041)**	$(85,621)	**$ 20,245**	$(3,241)

The following table shows the other comprehensive income (loss) arising from the change in additional minimum liability for the years ended December 31, 2005 and 2004 (dollars in thousands):

	2005	2004
Increase in minimum liability included in other comprehensive income – net of tax:		
Pinnacle West consolidated	**$ (15,489)**	$(15,224)
APS share	**$ (15,045)**	$(13,929)

The following table shows the weighted-average assumptions used for both the pension and other benefits to determine benefit obligations and net periodic benefit costs:

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,	
	2005	2004	**2005**	2004
Discount rate – pension	**5.66%**	5.84%	**5.84%**	6.10%
Discount rate – other benefits	**5.68%**	5.92%	**5.92%**	6.10%
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	**2010**	2009	**2009**	2008

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 2006, we are assuming a 9% long-term rate of return on plan assets, which we believe is reasonable given our asset allocation in relation to historical and expected 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	$ 7	$ (6)
Effect on service and interest cost components of net periodic other postretirement benefit costs	11	(9)
Effect on the accumulated other postretirement benefit obligation	100	(79)

Plan Assets

Pinnacle West's qualified pension plan asset allocation at December 31, 2005 and 2004 is as follows:

	Percentage of Plan Assets at December 31,		
	2005	2004	Target Asset Allocation
ASSET CATEGORY			
Equity securities	**59%**	60%	60%
Fixed Income	**26**	27	30%
Other	**15**	13	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, 2005 and 2004, is as follows:

	Percentage of Plan Assets at December 31,		
	2005	2004	Target Asset Allocation
ASSET CATEGORY			
Equity securities	**69%**	71%	70%
Fixed Income	**26**	23	27%
Other	**5**	6	3%
Total	**100%**	100%	

The Investment Management Committee, described above, has also been delegated oversight of the plan assets for the other 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 contribution to our pension plan in 2006 is estimated to be approximately $50 million. The contribution to our other postretirement benefit plans in 2006 is estimated to be approximately $29 million. APS' share is approximately 96% 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):

Year	Pension	Other Benefits (a)
2006	$ 52,675	$ 16,340
2007	56,891	17,751
2008	62,263	19,166
2009	68,651	20,775
2010	75,273	22,847
Years 2011-2015	520,961	149,784

(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 its subsidiaries. In 2005, costs related to APS' employees represented 96% 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, 2005, approximately 22% of total plan assets were in Pinnacle West stock. Pinnacle West recorded expenses for this plan of approximately $6 million for 2005 and $5 million for each of the years 2004 and 2003. APS recorded expenses for this plan of approximately $6 million in 2005, $5 million in 2004 and $5 million in 2003.

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 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 VIE's 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 $71 million in 2005, $69 million in 2004 and $67 million in 2003. APS' lease expense was $58 million in 2005, $57 million in 2004 and $66 million in 2003.

The amounts to be paid for the Palo Verde Unit 2 leases are approximately $49 million per year for the years 2006 to 2015.

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

Year	Pinnacle West Consolidated	APS
2006	$ 74	$ 66
2007	73	65
2008	71	64
2009	68	62
2010	65	60
Thereafter	303	288
Total future lease commitments	$654	$605

10. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. Pinnacle West Energy shared ownership of Silverhawk, which was sold on January 10, 2006. See Note 22. Our share of operations and maintenance expense related to these facilities is included in the Consolidated Statements of Income. The following table shows APS' interests in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2005 (dollars in thousands):

	Percent Owned	Plant in Service	Accumulated Depreciation	Construction Work in Progress
GENERATING FACILITIES				
Palo Verde Units 1 and 3	29.1%	$1,931,736	$ 923,052	$ 41,391
Palo Verde Unit 2 (see Note 9)	17.0%	671,775	260,840	6,363
Four Corners Units 4 and 5	15.0%	158,129	78,588	317
Navajo Generating Station Units 1, 2 and 3	14.0%	252,348	108,182	3,963
Cholla common facilities (a)	62.6%(b)	87,165	38,832	2,109
TRANSMISSION FACILITIES				
ANPP 500KV System	35.8%(b)	81,117	22,829	815
Navajo Southern System	31.4%(b)	29,809	13,273	6,813
Palo Verde – Yuma 500KV System	23.9%(b)	9,580	3,945	386
Four Corners Switchyards	27.5%(b)	3,120	1,267	–
Phoenix – Mead System	17.1%(b)	36,020	3,770	–
Palo Verde – Estrella 500KV System	55.5%(b)	74,243	2,023	–
Harquahala	80.0%(b)	–	–	112

(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 Policy 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.

APS has existing fuel storage pools at Palo Verde and is operating a 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 $147 million (in 2005 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. At December 31, 2005, APS had a regulatory asset of $6 million that represents amounts spent for on-site interim spent fuel storage net of amounts recovered in rates per the ACC rate order that was effective April 1, 2005.

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 $15 million per incident, to be periodically adjusted for inflation. 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 $13 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 accidental outage of any of the three units. The property damage, decontamination, and replacement power coverages are provided by Nuclear Electric Insurance Limited (NEIL). APS is subject to retrospective assessments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount of retrospective assessments APS could incur under the current NEIL policies totals $17.8 million. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

Fuel and Purchased Power Commitments

Pinnacle West and APS are parties to various fuel and purchased power contracts with terms expiring between 2006 and 2025 that include required purchase provisions. Pinnacle West estimates the contract requirements to be approximately $316 million in 2006; $239 million in 2007; $180 million in 2008; $139 million in 2009; $117 million in 2010 and $908 million thereafter. APS estimates the contract requirements to be approximately $265 million in 2006; $179 million in 2007; $152 million in 2008; $139 million in 2009; $117 million in 2010 and $896 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 fuel and purchased power 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 2024.

The following table summarizes our actual and estimated take-or-pay commitments (dollars in millions):

	Actual			Estimated (a)					
	2003	2004	2005	2006	2007	2008	2009	2010	Thereafter
Coal take-or-pay commitments	$ 43	$ 41	$ 48	$ 67	$ 69	$ 78	$ 93	$ 73	$611

(a) Total take-or-pay commitments are approximately $991 million. The total net present value of these commitments is approximately $598 million.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS' coal mine reclamation obligation was $75 million at December 31, 2005 and $61 million at December 31, 2004 and is included in Deferred Credits and 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. However, on September 6, 2005, the Ninth Circuit issued a decision, concluding that the FERC may not order refunds from entities that are not within the FERC's jurisdiction. Because a number of the entities owing refunds under the FERC's calculations are not within the FERC's jurisdiction, this order may affect the level of recovery of refunds due in this proceeding. In addition, on August 8, 2005, the FERC issued an order allowing sellers in the California markets to demonstrate that its refund methodology results in an overall revenue shortfall for their transactions in the relevant markets over a specified time frame. More than twenty sellers made such cost recovery filings on September 14, 2005. On January 26, 2006, the FERC conditionally accepted thirteen of these filings, reducing the refund liability for these sellers. Correspondingly, this will reduce the recovery of total refunds in the California markets. We currently believe the refund claims at FERC will have no material adverse impact on our financial position, results of operations, cash flow or liquidity.

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. 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. Several of the intervenors in this appeal filed a petition for rehearing of this decision on October 25, 2004. The petition for rehearing has not been acted upon, and 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 Ninth Circuit Court of Appeals. 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 cash flows.

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 Independent System Operator 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

APS has been 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. 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. 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, cash flow or liquidity.

Construction Program

Consolidated capital expenditures in 2006 are estimated to be (dollars in millions):

APS	$649
SunCor	232
Other	6
Total	$887

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 were 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. On December 28, 2004, the D.C. Court of Appeals 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 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, for the period September 2003 through December 2005. This appeal has been stayed pending further consideration by the FERC.

Consistent with its obligations under the 1996 settlement, El Paso filed a new rate case on June 30, 2005, which proposed new rates and new services to become effective on January 1, 2006. The FERC suspended the effectiveness of these new rates and services until January 1, 2006 and made the rates subject to refund pending the outcome of a hearing. As part of an ongoing technical conference and settlement discussions, El Paso has agreed to postpone the implementation and the associated cost impact of the new services until April 1, 2006. APS will be able to evaluate the cost impact of these new services once the FERC issues a final order on the technical conference. APS cannot currently predict the outcome of this matter.

Navajo Nation Litigation

In June 1999, the Navajo Nation served Salt River Project with a lawsuit filed in the United States District Court for the District of Columbia (the "D.C. 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. 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 filed in the Circuit Court for the City of St. Louis 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." 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.

Superfund

Superfund establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are PRPs. PRPs may be strictly, and often jointly and severally, liable for clean-up. On September 3, 2003, the EPA advised APS that the EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 (OU3) in Phoenix, Arizona. APS has facilities that are within this superfund site. APS and Pinnacle West have agreed with the EPA to perform certain investigative activities of the APS facilities within OU3. Because the investigation has not yet been completed and ultimate remediation requirements are not yet finalized, neither APS nor Pinnacle West can currently estimate the expenditures which may be required.

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.

Additionally, APS has aquifer protection permits for some of its generation sites that require the closure of certain facilities at those sites. The generation sites are strategically located to serve APS native load customers. Management expects to continuously use the sites and, thus, cannot estimate a potential closure date. 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 debt securities and domestic equity securities. APS applies the provisions of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity

Securities," in accounting for investments in decommissioning trust funds, and classifies these investments as available for sale. As a result, we record the decommissioning trust funds at their fair value on our Consolidated Balance Sheets. Because of the ability of APS to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, APS has recorded the offsetting amount of unrealized gains (losses) on investment securities in other regulatory liabilities/assets.

The following table summarizes the fair value of APS' nuclear decommissioning trust fund assets at December 31, 2005 and December 31, 2004 (dollars in millions):

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
2005			
Equity securities	**$150**	**$ 50**	**$ –**
Debt securities	**144**	**3**	**1**
Total	**$294**	**$ 53**	**$ 1**
2004			
Equity securities	$135	$ 45	$ –
Debt securities	133	6	–
Total	$268	$ 51	$ –

The costs of securities sold are determined on the basis of specific identification. The following table sets forth approximate gains and losses and proceeds from the sale of securities by the nuclear decommissioning trust funds (dollars in millions):

Year Ended December 31,	**2005**	2004	2003
Realized gains	**$ 6**	$ 1	$ 2
Realized losses	**(6)**	(2)	(1)
Proceeds from the sale of securities	**186**	124	169

The fair value of debt securities, summarized by contractual maturities, at December 31, 2005 is as follows:

	Fair Value (in millions)
Less than one year	**$ 18**
1 year – 5 years	**35**
5 years – 10 years	**36**
Greater than 10 years	**55**
Total	**$144**

The following schedule shows the change in our asset retirement obligations for 2005 and 2004 (dollars in millions):

	2005	2004
Asset retirement obligation at the beginning of year	**$252**	$234
Changes attributable to:		
Liabilities settled	**(2)**	(1)
Accretion expense	**17**	17
Estimated cash flow revisions	**2**	2
Asset retirement obligation at the end of year	**$269**	$252

In accordance with SFAS No. 71, APS accrues for removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 1.

13. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following note presents quarterly financial information for 2005 and 2004. We are disclosing originally reported amounts and revised amounts in each period for the reclassification of certain commercial properties at SunCor and Silverhawk as discontinued operations (see Note 22).

Consolidated quarterly financial information for 2005 and 2004 is as follows (dollars in thousands, except per share amounts):

	2005 Quarter Ended				2005
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total
As originally reported:					
Operating revenues	$615,087	$755,836	$955,583		
Operations and maintenance	156,496	153,097	158,940		
Operating income	85,256	178,627	162,113		
Income taxes	14,732	55,024	40,305		
Income from continuing operations	23,656	85,156	84,694		
SunCor reclassifications (see Note 22):					
Operating revenues	(2,120)	(494)	–		
Operating income	(529)	205	(268)		
Income taxes	(91)	(36)	–		
Income from continuing operations	(142)	(55)	–		
Silverhawk reclassifications (see Note 22):					
Operating revenues	(27,609)	–	–		
Operations and maintenance	(1,412)	–	–		
Operating income	7,098	–	–		
Income taxes	3,929	–	–		
Income from continuing operations	6,085	–	–		
After SunCor and Silverhawk reclassifications:					
Operating revenues	$585,358	$755,342	$955,583	$691,672	$2,987,955
Operations and maintenance	155,084	153,097	158,940	168,706	635,827
Operating income	91,825	178,832	161,845	82,787	515,289
Income taxes	18,570	54,988	40,305	13,029	126,892
Income from continuing operations	29,599	85,101	84,694	23,769	223,163
Net income	24,448	26,735	103,737	21,347	176,267

	2004 Quarter Ended				2004
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total
As originally reported:					
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	31,426	72,640	105,400	33,729	243,195
SunCor reclassifications (see Note 22):					
Operating revenues	(2,293)	(2,592)	(2,318)	(2,274)	(9,477)
Operating income	(552)	(625)	(415)	375	(1,217)
Income taxes	(26)	(48)	51	168	145
Income from continuing operations	(41)	(75)	80	261	225
Silverhawk reclassifications (See Note 22):					
Operating revenues	301	(5,084)	(37,296)	(19,163)	(61,242)
Operations and maintenance	–	(380)	(2,158)	(1,699)	(4,237)
Operating income	300	3,002	(1,065)	10,686	12,923
Income taxes	(108)	1,801	232	5,215	7,140
Income from continuing operations	(170)	2,813	363	8,141	11,147
After SunCor and Silverhawk reclassifications:					
Operating revenues	$ 564,353	$ 704,207	$ 847,165	$ 713,281	$2,829,006
Operations and maintenance	137,386	138,595	158,607	157,732	592,320
Operating income	83,946	122,857	209,356	101,806	517,965
Income taxes	15,334	44,959	59,183	16,666	136,142
Income from continuing operations	30,580	73,961	104,329	37,720	246,590
Net income	31,426	72,640	105,400	33,729	243,195

2005 Quarter Ended	March 31,	June 30,	Sept. 30,	Dec. 31,
As originally reported – Basic earnings per share (a):				
Income From Continuing Operations	**$ 0.26**	**$ 0.89**	**$ 0.86**	**$ 0.24**
Net Income	**0.27**	**0.28**	**1.05**	**0.22**
After SunCor and Silverhawk reclassifications –				
Basic earnings per share (a):				
Income from Continuing Operations	**0.32**	**0.88**	**0.86**	**0.24**
Net Income	**0.27**	**0.28**	**1.05**	**0.22**
As originally reported – Diluted earnings per share (a):				
Income From Continuing Operations	**0.26**	**0.88**	**0.86**	**0.24**
Net Income	**0.27**	**0.28**	**1.05**	**0.22**
After SunCor and Silverhawk reclassifications –				
Diluted earnings per share (a):				
Income From Continuing Operations	**$ 0.32**	**$ 0.88**	**$ 0.86**	**$ 0.24**
Net Income	**0.27**	**0.28**	**1.05**	**0.22**

2004 Quarter Ended	March 31,	June 30,	Sept. 30,	Dec. 31,
As originally reported – Basic earnings per share (a):				
Income From Continuing Operations	$ 0.34	$ 0.78	$ 1.14	$ 0.32
Net Income	0.34	0.80	1.15	0.37
After SunCor and Silverhawk reclassifications –				
Basic earnings per share (a):				
Income From Continuing Operations	0.33	0.81	1.14	0.41
Net Income	0.34	0.80	1.15	0.37
As originally reported – Diluted earnings per share (a):				
Income From Continuing Operations	0.34	0.78	1.14	0.32
Net Income	0.34	0.79	1.15	0.37
After SunCor and Silverhawk reclassifications –				
Diluted earnings per share (a):				
Income From Continuing Operations	$ 0.33	$ 0.81	$ 1.14	$ 0.41
Net Income	0.34	0.79	1.15	0.37

(a) The difference between originally reported and revised basic and diluted earnings per share related to the sale of certain commercial properties at SunCor and the sale of Silverhawk (see Note 22), which changed reported amounts for the quarters in 2005 and 2004.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

Pinnacle West and APS believe that the carrying amounts of their cash equivalents are reasonable estimates of their fair values at December 31, 2005 and 2004 due to their short maturities.

Pinnacle West and APS 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, 2005 and 2004 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, 2005 and 2004 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, 2005, the carrying value of our long-term debt for Pinnacle West, excluding capitalized lease obligations and interest rate swap (see "Fair Value Hedges" – Note 18), was $2.99 billion, with an estimated fair value of $3.00 billion. See Note 18 for fair value of the interest rate swap. The carrying value of our long-term debt for Pinnacle West (excluding capitalized lease obligations) was $3.19 billion on December 31, 2004, with an estimated fair value of $3.30 billion. On December 31, 2005, the carrying value of APS' long-term debt (excluding capitalized lease obligations) was $2.56 billion, with an estimated fair value of $2.57 billion. The carrying value of APS' long-term debt (excluding capital lease obligations) was $2.71 billion on December 31, 2004, with an estimated fair value of $2.81 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, 2005, 2004 and 2003:

	2005	2004	2003
Basic earnings per share:			
Income from continuing operations	**$ 2.31**	$ 2.70	$ 2.47
Income (loss) from discontinued operations	**(0.48)**	(0.04)	0.17
Earnings per share – basic	**$ 1.83**	$ 2.66	$ 2.64
Diluted earnings per share:			
Income from continuing operations	**$ 2.31**	$ 2.69	$ 2.47
Income (loss) from discontinued operations	**(0.49)**	(0.03)	0.16
Earnings per share – diluted	**$ 1.82**	$ 2.66	$ 2.63

Dilutive stock options increased average common shares outstanding by approximately 106,000 shares in 2005, 135,000 shares in 2004 and 140,000 shares in 2003. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 96,589,949 shares in 2005, 91,532,473 shares in 2004 and 91,405,134 shares in 2003.

Options to purchase 495,367 shares of common stock were outstanding at December 31, 2005 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 1,058,616 at December 31, 2004 and 2,291,646 at December 31, 2003.

16. STOCK-BASED COMPENSATION

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

The 2002 Long-Term Incentive Plan (2002 plan) allows Pinnacle West to grant performance shares, stock ownership incentive awards and non-qualified and performance-accelerated stock options to key employees. We have 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 Long-Term Incentive Plan ("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. 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 $6 million in 2005, $8 million in 2004 and $6 million in 2003 for Pinnacle West. APS' share was $5 million in 2005, $6 million in 2004 and $3 million in 2003.

The following table is a summary of the status of outstanding stock options under our equity incentive plans as of December 31, 2005, 2004 and 2003 and changes during the years ending on those dates:

	2005 Shares	**2005 Weighted Average Exercise Price**	2004 Shares	2004 Weighted Average Exercise Price	2003 Shares	2003 Weighted Average Exercise Price
Outstanding at beginning of year	**2,276,123**	**$ 39.14**	2,698,246	$38.56	2,185,129	$39.96
Granted	**–**	**–**	37,580	37.85	621,875	32.29
Exercised	**(478,851)**	**36.54**	(372,205)	34.02	(62,366)	26.09
Forfeited	**(101,500)**	**43.04**	(87,498)	42.31	(46,392)	37.61
Outstanding at year-end	**1,695,772**	**39.65**	2,276,123	39.14	2,698,246	38.56
Options exercisable at year-end	**1,499,302**	**40.55**	1,859,340	40.59	1,787,622	40.35
Weighted average grant date fair value of options granted during the year		**$ –**		$ 3.53		$ 7.37

The following table summarizes information about our stock options at December 31, 2005:

Exercise Prices Per Share	Options Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contract Life (Years)	Options Exercisable	Weighted Average Exercise Price
$ 28.07 – 32.75	**341,902**	**$ 32.24**	**6.6**	**160,372**	**$ 32.18**
32.75 – 37.42	**67,081**	**34.66**	**3.7**	**67,081**	**34.66**
37.42 – 42.10	**540,855**	**38.89**	**5.2**	**525,915**	**38.92**
42.10 – 46.78	**745,934**	**44.04**	**4.6**	**745,934**	**44.04**
	1,695,772			**1,499,302**	

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, 2005, 2004 and 2003:

	2005 Shares	**2005 Grant Date Fair Value**	2004 Shares	2004 Grant Date Fair Value	2003 Shares	2003 Grant Date Fair Value
Restricted stock	**–**	**$ –**	4,000	$ 37.68(a)	4,000	$ 32.20(a)
Performance share awards	**215,300**	**41.36(b)**	215,285	37.85(b)	119,085	32.29(b)
Stock ownership incentive awards	**11,322**	**44.13(b)**	9,015	40.29(b)	–	–

(a) Restricted stock priced at the average of the high and low market price on the grant date.
(b) Performance shares and stock ownership incentive awards priced at the closing market price on the grant date.

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

Financial data for 2005, 2004 and 2003 by business segments is provided as follows (dollars in millions):

Business Segments for the Year Ended December 31, 2005

	Regulated Electricity	Real Estate	Marketing and Trading	Other	Total
Operating revenues (a)	**$ 2,237**	**$ 338**	**$ 352**	**$ 61**	**$ 2,988**
Purchased power and fuel costs	**595**	**–**	**293**	**–**	**888**
Other operating expenses	**740**	**278**	**28**	**52**	**1,098**
Regulatory disallowance (see Note 3)	**139**	**–**	**–**	**–**	**139**
Operating margin	**763**	**60**	**31**	**9**	**863**
Depreciation and amortization	**343**	**3**	**2**	**–**	**348**
Interest expense	**169**	**2**	**2**	**–**	**173**
Other expense (income)	**(6)**	**(3)**	**–**	**1**	**(8)**
Income from continuing operations before income taxes	**257**	**58**	**27**	**8**	**350**
Income taxes	**90**	**23**	**11**	**3**	**127**
Income from continuing operations	**167**	**35**	**16**	**5**	**223**
Income (loss) from discontinued operations – net of income tax benefit of $(30) (see Note 22) (b)(c)	**–**	**17**	**(67)**	**3**	**(47)**
Net income (loss)	**$ 167**	**$ 52**	**$ (51)**	**$ 8**	**$ 176**
Total assets	**$ 9,732**	**$ 483**	**$ 1,070**	**$ 38**	**$ 11,323**
Capital expenditures	**$ 811**	**$ 106**	**$ 11**	**$ –**	**$ 928**

Business Segments for the Year Ended December 31, 2004

	Regulated Electricity	Real Estate	Marketing and Trading	Other	Total
Operating revenues	$ 2,035	$ 350	$ 401	$ 43	$ 2,829
Purchased power and fuel costs	567	–	321	–	888
Other operating expenses	683	284	30	34	1,031
Operating margin	785	66	50	9	910
Depreciation and amortization	384	4	4	–	392
Interest expense	170	1	1	–	172
Other expense (income) (d)	4	(6)	(2)	(33)	(37)
Income from continuing operations before income taxes	227	67	47	42	383
Income taxes	75	27	18	16	136
Income from continuing operations	152	40	29	26	247
Income (loss) from discontinued operations – net of income tax benefit of $(2) (see Note 22) (b)(c)	–	4	(12)	4	(4)
Net income	$ 152	$ 44	$ 17	$ 30	$ 243
Total assets	$ 8,674	$ 454	$ 746	$ 23	$ 9,897
Capital expenditures	$ 483	$ 81	$ 34	$ –	$ 598

Business Segments for the Year Ended December 31, 2003	Regulated Electricity	Real Estate	Marketing and Trading	Other	Total
Operating revenues	$ 1,978	$ 362	$ 391	$ 28	$ 2,759
Purchased power and fuel costs	517	–	345	–	862
Other operating expenses	625	306	34	24	989
Operating margin	836	56	12	4	908
Depreciation and amortization	428	6	1	–	435
Interest expense	172	2	–	–	174
Other expense (income)	(4)	(25)	–	–	(29)
Income from continuing operations before income taxes	240	73	11	4	328
Income taxes	70	28	3	2	103
Income from continuing operations	170	45	8	2	225
Income from discontinued operations – net of income taxes of $9 (see Note 22) (b)(c)	–	10	1	5	16
Net income	$ 170	$ 55	$ 9	$ 7	$ 241
Capital expenditures	$ 686	$ 72	$ 9	$ –	$ 767

(a) Effective April 1, 2005, revenues of approximately $40 million from Off-System Sales, which were previously reported in the marketing and trading segment, began being reported in the regulated electricity segment in accordance with the retail rate case settlement.

(b) The marketing and trading segment relates to the sale and operations of Silverhawk. See Note 22.

(c) The other segment relates to the sale and operations of NAC. See Note 22.

(d) The other segment includes a $35 million pre-tax ($21 million after-tax) gain related to the sale of a limited partnership interest in the Phoenix Suns in 2004.

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, 2005, we hedged certain exposures to the price variability of commodities for a maximum of 3.25 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 qualify for 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 qualify for 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, the effective portion of 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.

For its regulated operations, APS defers for future rate recovery 90% of gains and losses on derivatives that would otherwise be recognized in income. To the extent the amounts that would otherwise be recognized in income are eligible to be recovered through the PSA, the amounts will be recorded as either a regulatory asset or liability and have no effect on earnings.

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 qualify for 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. Realized 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 fuel and purchased power costs in our Consolidated Statement of Income, but this does not impact our financial condition, net income or cash flows.

Cash Flow Hedges

The changes in the fair value of our hedged positions included in the Consolidated Statements of Income, after consideration of amounts deferred under the PSA, for the years ended December 31, 2005, 2004 and 2003 are comprised of the following (dollars in thousands):

	2005	2004	2003
Gains (losses) on the ineffective portion of derivatives qualifying for hedge accounting	**$14,289**	$ (1,568)	$ 8,237
Gains from the change in options' time value excluded from measurement of effectiveness	**620**	185	181
Gains from the discontinuance of cash flow hedges	**556**	1,137	–

During 2006, we estimate that a net gain of $216 million before income taxes will be reclassified from accumulated other comprehensive income as an offset to the effect of market price changes for the related hedged transactions. To the extent the amounts are eligible for inclusion in the PSA, the amounts will be recorded as either a regulatory asset or liability and have no effect on earnings (see Note 3).

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

The following table summarizes our assets and liabilities from risk management and trading activities at December 31, 2005 and 2004 (dollars in thousands):

	December 31, 2005				
	Current Assets	Investments and Other Assets	Current Liabilities	Deferred Credits and Other	Net Asset (Liability)
Regulated electricity:					
Mark-to-market	**$ 516,399**	**$ 228,873**	**$ (335,801)**	**$ (74,787)**	**$ 334,684**
Margin account and options	**1,814**	**–**	**(124,165)**	**–**	**(122,351)**
Marketing and trading:					
Mark-to-market	**307,883**	**291,122**	**(236,922)**	**(181,417)**	**180,666**
Options and emission allowances – at cost	**1,683**	**77,836**	**(23,805)**	**(209)**	**55,505**
Total	**$ 827,779**	**$ 597,831**	**$ (720,693)**	**$ (256,413)**	**$ 448,504**

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

We maintain a margin account with a broker to support our risk management and trading activities. The margin account was a liability of $123 million at December 31, 2005 and $9 million at December 31, 2004 and is included in the margin account in the table above. Cash is deposited with the broker in this account at the time futures or options contracts are initiated. The change in market value of these contracts (reflected in mark-to-market) requires adjustment of the margin account balance.

Cash or other assets may be required to serve as collateral against our open positions on certain energy-related contracts. Collateral provided to counterparties was $6 million at December 31, 2005 and $1 million at December 31, 2004, and is included in other current assets on the Consolidated Balance Sheets. Collateral provided to us by counterparties was $216 million at December 31, 2005 and $24 million at December 31, 2004, and is included in other current liabilities on the Consolidated Balance Sheets.

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 a loss of $1.5 million at December 31, 2005 and is included in other current liabilities with the corresponding offset in current maturities of long-term debt on the Consolidated Balance Sheets. 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 non-performance or non-payment by counterparties. We have risk management and trading contracts with many counterparties. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of counterparties are rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. 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 2005, 2004 and 2003 (dollars in thousands):

Year Ended December 31,	**2005**	2004	2003
Other income:			
Investment gains – net (a)	**$ 752**	$ 38,256	$ 3,649
Interest income	**14,793**	6,770	4,412
SunCor (b)	**2,623**	4,458	24,740
Asset sales	**3,187**	3,026	618
Miscellaneous	**2,005**	779	2,144
Total other income	**$ 23,360**	$ 53,289	$ 35,563
Other expense:			
Non-operating costs (c)	**$ (13,589)**	$ (15,524)	$ (14,959)
Asset dispositions	**(9,759)**	(1,212)	(1,522)
Miscellaneous	**(3,368)**	(4,604)	(4,093)
Total other expense	**$ (26,716)**	$ (21,340)	$ (20,574)

(a) Includes a $35 million gain ($21 million after tax) related to the sale of a limited partnership interest in the Phoenix Suns in 2004.
(b) Primarily related to the sale at SunCor of a land interest and profit participation agreement in 2003 for $18 million. Includes joint venture and other non-operating income.
(c) As defined by the FERC, includes below-the-line non-operating utility costs (primarily community relations and other costs excluded from utility rate recovery).

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, 2005, APS would have been required to assume approximately $234 million of debt and pay the equity participants approximately $185 million.

SunCor has certain land development arrangements that are required to be consolidated under FIN 46R, "Consolidation of Variable Interest Entities." The assets and non-controlling interests reflected in our Consolidated Balance Sheets related to these arrangements were approximately $34 million at December 31, 2005 and 2004.

21. GUARANTEES

We have issued parental guarantees and letters of credit and obtained surety bonds on behalf of our unregulated subsidiaries. Our parental guarantee for Pinnacle West Energy relates to a purchased power agreement. Our credit support instruments enable APS Energy Services to offer commodity energy and energy-related products. Non-performance or non-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, 2005 are as follows (dollars in millions):

	Guarantees		Surety Bonds	
	Amount	Term (in years)	Amount	Term (in years)
Parental:				
Pinnacle West Energy	$ 5	1	$ –	–
APS Energy Services	20	1	65	1
Total	$ 25		$ 65	

At December 31, 2005, we had entered into approximately $37 million of letters of credit which supported transmission agreements related to Silverhawk. These letters of credit terminated as a result of the sale of Silverhawk. See Note 22 for a discussion of the sale of Silverhawk. At December 31, 2005, Pinnacle West had approximately $4 million of letters of credit related to workers' compensation expiring in 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.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2005, 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 and expire in 2010. APS has also entered into approximately $98 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 2010. 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 enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. APS has agreed to indemnify 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 provisions and therefore, the overall maximum amount of the obligation under such indemnification provisions 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 indemnification provisions is likely.

22. DISCONTINUED OPERATIONS

Silverhawk (marketing and trading segment) – In June 2005, we entered into an agreement to sell our 75% interest in Silverhawk to NPC. The sale was completed on January 10, 2006. As a result of this sale, we recorded a loss from discontinued operations of approximately $56 million ($91 million pretax) in the second quarter of 2005. The amounts in the chart below also include the revenues and expenses related to the operations of Silverhawk. The assets held for sale at December 31, 2005 were $203 million, of which property, plant and equipment accounted for approximately $197 million.

Concurrent with the execution of the agreement to sell our interest in Silverhawk, GenWest and NPC also entered into a Purchase Power Agreement ("PPA") providing for the sale of GenWest's share of the capacity and output of Silverhawk to NPC. The PPA commenced on October 1, 2005 and was terminated on January 10, 2006, the date of the sale under the Purchase Agreement.

SunCor (real estate segment) – In 2005, SunCor sold commercial properties, which are required to be reported as discontinued operations on Pinnacle West's Consolidated Statements of Income in accordance with SFAS No. 144. As a result of the sales, we recorded a gain from discontinued operations of approximately $15 million ($25 million pretax) in the third quarter of 2005.

NAC (other segment) – In 2004, we sold our investment in NAC, and in 2005 we recognized a gain of $4 million ($6 million pretax) in connection with the sale that had previously been subject to contingencies.

The following table provides revenue, income (loss) before income taxes and after-tax income classified as discontinued operations in Pinnacle West's Consolidated Statements of Income for the years ended December 31, 2005, 2004 and 2003 (dollars in millions):

	2005	2004	2003
Revenue:			
Silverhawk	**$ 95**	$ 61	$ 1
SunCor – commercial operations	**9**	21	71
NAC	**–**	34	58
Total revenue	**$ 104**	$ 116	$ 130
Income (loss) before taxes:			
Silverhawk (a)	**$(111)**	$ (18)	$ –
SunCor – commercial operations	**28**	6	17
NAC	**6**	7	8
Total income (loss) before taxes	**$ (77)**	$ (5)	$ 25
Income (loss) after taxes:			
Silverhawk	**$ (67)**	$ (12)	$ 1
SunCor – commercial operations	**17**	4	10
NAC	**3**	4	5
Total income (loss) after taxes	**$ (47)**	$ (4)	$ 16

(a) Income before income taxes includes an interest expense allocation, net of capitalized amounts, of $13 million in 2005 and $6 million in 2004. The allocation was based on Pinnacle West's weighted-average interest rate applied to the net property, plant and equipment.

CERTIFICATIONS

On June 16, 2005, 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 13, 2006, 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 to the Company's Annual Report on Form 10-K for fiscal year 2005.

NON-GAAP FINANCIAL MEASURE RECONCILIATION – OPERATING INCOME (GAAP MEASURE) TO GROSS MARGIN (NON-GAAP FINANCIAL MEASURE) (dollars in thousands)

	Twelve Months Ended December 31,		Increase (Decrease)	
	2005	2004	Pretax	After Tax
RECONCILIATION OF REGULATED ELECTRICITY SEGMENT GROSS MARGIN				
Operating Income (closest GAAP measure)	**$ 515,289**	$ 517,965	$ (2,676)	$ (1,632)
Plus:				
Operations and maintenance	**635,827**	592,320	43,507	26,526
Real estate segment operations	**278,366**	284,194	(5,828)	(3,553)
Depreciation and amortization	**347,652**	391,597	(43,945)	(26,793)
Taxes other than income taxes	**132,040**	120,722	11,318	6,901
Other expenses	**51,987**	34,108	17,879	10,901
Regulatory disallowance	**138,562**	–	138,562	84,481
Marketing and trading segment fuel and purchased power	**293,091**	320,667	(27,576)	(16,813)
Less:				
Real estate segment revenues	**338,031**	350,315	(12,284)	(7,490)
Other revenues	**61,221**	42,816	18,405	11,222
Marketing and trading segment revenues	**351,558**	400,628	(49,070)	(29,918)
Regulated electricity segment gross margin	**$1,642,004**	$1,467,814	$ 174,190	$ 106,204
RECONCILIATION OF MARKETING AND TRADING SEGMENT GROSS MARGIN				
Operating Income (closest GAAP measure)	**$ 515,289**	$ 517,965	$ (2,676)	$ (1,632)
Plus:				
Operations and maintenance	**635,827**	592,320	43,507	26,526
Real estate segment operations	**278,366**	284,194	(5,828)	(3,553)
Depreciation and amortization	**347,652**	391,597	(43,945)	(26,793)
Taxes other than income taxes	**132,040**	120,722	11,318	6,901
Other expenses	**51,987**	34,108	17,879	10,901
Regulatory disallowance	**138,562**	–	138,562	84,481
Regulated electricity segment fuel and purchased power	**595,141**	567,433	27,708	16,894
Less:				
Real estate segment revenues	**338,031**	350,315	(12,284)	(7,490)
Other revenues	**61,221**	42,816	18,405	11,222
Regulated electricity segment revenues	**2,237,145**	2,035,247	201,898	123,097
Marketing and trading segment gross margin	**$ 58,467**	$ 79,961	$ (21,494)	$ (13,104)

NON-GAAP FINANCIAL MEASURE RECONCILIATION – OPERATING INCOME (GAAP MEASURE) TO GROSS MARGIN (NON-GAAP FINANCIAL MEASURE) (dollars in thousands)

	Twelve Months Ended December 31, 2004	2003	Increase (Decrease) Pretax	After Tax
RECONCILIATION OF REGULATED ELECTRICITY SEGMENT GROSS MARGIN				
Operating Income (closest GAAP measure)	$ 517,965	$ 473,252	$ 44,713	$ 27,262
Plus:				
Operations and maintenance	592,320	548,732	43,588	26,576
Real estate segment operations	284,194	305,974	(21,780)	(13,279)
Depreciation and amortization	391,597	435,140	(43,543)	(26,548)
Taxes other than income taxes	120,722	110,270	10,452	6,373
Other expenses	34,108	23,254	10,854	6,618
Marketing and trading segment fuel and purchased power	320,667	344,862	(24,195)	(14,752)
Less:				
Real estate segment revenues	350,315	361,604	(11,289)	(6,883)
Other revenues	42,816	27,929	14,887	9,077
Marketing and trading segment revenues	400,628	391,196	9,432	5,751
Regulated electricity segment gross margin	$1,467,814	$1,460,755	$ 7,059	$ 4,305
RECONCILIATION OF MARKETING AND TRADING SEGMENT GROSS MARGIN				
Operating Income (closest GAAP measure)	$ 517,965	$ 473,252	$ 44,713	$ 27,262
Plus:				
Operations and maintenance	592,320	548,732	43,588	26,576
Real estate segment operations	284,194	305,974	(21,780)	(13,279)
Depreciation and amortization	391,597	435,140	(43,543)	(26,548)
Taxes other than income taxes	120,722	110,270	10,452	6,373
Other expenses	34,108	23,254	10,854	6,618
Regulated electricity segment fuel and purchased power	567,433	517,320	50,113	30,554
Less:				
Real estate segment revenues	350,315	361,604	(11,289)	(6,883)
Other revenues	42,816	27,929	14,887	9,077
Regulated electricity segment revenues	2,035,247	1,978,075	57,172	34,858
Marketing and trading segment gross margin	$ 79,961	$ 46,334	$ 33,627	$ 20,504