

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

#### Consolidation and Nature of Operations

The 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). 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 the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells and delivers electricity to wholesale customers in the western United States. In early 2003, the marketing and trading division of Pinnacle West was moved to APS for future marketing and trading activities (existing wholesale contracts remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy. See Note 3 for a discussion of the Track A Order. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we conduct our unregulated generation operations. APS Energy Services was formed in 1998 and provides competitive commodity energy and energy-related products to key customers in competitive markets in the western United States. SunCor is a developer of residential, commercial and industrial real estate projects in Arizona, New Mexico, Idaho and Utah. El Dorado is an investment firm, and its principal investment is in NAC, which is a company specializing in spent nuclear fuel technology.

#### 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. We manage risks associated with these market fluctuations by utilizing various commodity instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. 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 ERM, 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." 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 hedge criteria are met, in common stock equity (as a component of other comprehensive income (loss)). SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard.

Prior to the fourth quarter of 2002, we accounted for our trading activity at fair value, with changes in fair value reported in earnings as required by EITF 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." In the fourth quarter of 2002, we adopted EITF 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," which rescinded EITF 98-10. We recorded a \$66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Energy trading contracts that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

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

#### Mark-to-Market Accounting

Under mark-to-market accounting, derivative contracts for the purchase or sale of energy commodities are reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as current or long-term assets and liabilities from risk management and trading activities in 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. We convert quarterly and calendar year quotes into monthly prices based on historical relationships.

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

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

The credit valuation adjustment represents estimated credit losses on our overall exposure to counterparties, taking into account netting arrangements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. 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. See Note 18 for further discussion on credit risk.

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 ERM.

### 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 the recovery of expected future costs in current customer rates.

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

As part of the 1999 Settlement Agreement with the ACC (see Note 3), we continue to amortize certain regulatory assets over an eight-year period as follows (dollars in millions):

1999	2000	2001	2002	2003	2004	TOTAL
\$164	\$158	\$145	\$115	\$86	\$18	\$686

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

December 31,	2003	2002
Remaining balance recoverable under the 1999 Settlement Agreement (a)	\$ 18	\$ 104
Spent nuclear fuel storage (Note 11)	49	46
Electric industry restructuring transition costs (Note 3)	46	40
Deferred compensation	24	23
Contributions in aid of construction	11	10
Loss on reacquired debt (b)	12	9
Other	5	9
<b>Total regulatory assets</b>	<b>\$ 165</b>	<b>\$ 241</b>

(a) The majority of our unamortized regulatory assets above relates to deferred income taxes (see Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" below).

(b) See "Reacquired Debt Costs" below.

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

December 31,	2003	2002
Removal costs (a)	\$ 480	\$ –
Deferred gains on utility property	20	20
Deferred interest income (b)	8	–
Other	2	6
Total regulatory liabilities	\$ 510	\$ 26

(a) See Note 12 for information on Asset Retirement Obligations.

(b) See "ACC Financing Orders" in Note 3 for information on the "APS Loan".

#### Rate Synchronization Cost Deferrals

As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). In accordance with the 1999 Settlement Agreement, we are continuing to accelerate the amortization of the deferrals over an eight-year period that will end June 30, 2004. Amortization of the deferrals is included in depreciation and amortization expense in the Consolidated Statements of Income.

#### Utility Plant and Depreciation

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

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

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Prior to 2003, we charged removal costs, less salvage, to accumulated depreciation. Effective January 1, 2003, we applied the provisions of SFAS 143 (see Note 12).

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, 2003 were as follows:

- Fossil plant – 23 years;
- Nuclear plant – 20 years;
- Other generation – 29 years;
- Transmission – 36 years;

- Distribution – 23 years; and
- Other – 9 years.

For the years 2001 through 2003, the depreciation rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 12.5%. The weighted-average rate was 3.35% for 2003, 3.35% for 2002 and 3.40% for 2001. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

#### El Dorado Investments

El Dorado accounts for its investments using the consolidated (if controlled), equity (if significant influence) and cost (less than 20% ownership) methods. Beginning in the third quarter of 2002, El Dorado began consolidating the operations of NAC.

#### Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction projects. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. The rate used to calculate capitalized interest was a composite rate of 4.55% for 2003, 4.80% for 2002 and 6.13% for 2001. 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 utility plant. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

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

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

#### Electric Revenues

We derive electric revenues from sales of electricity to our regulated Native Load customers and sales to other parties from our marketing and trading activities. Revenues related to the sale of

electricity are generally recorded when service is rendered or electricity is delivered to customers. However, the determination and billing of electricity sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers since the date of the last meter reading and billing and the corresponding unbilled revenue are estimated. We exclude sales taxes on electric revenues from both revenue and taxes other than income taxes. Revenues from our Native Load customers and non-derivative instruments are reported on a gross basis in our Consolidated Statements of Income.

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.

We adopted EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in Issue No. 02-3," effective October 1, 2003. EITF 03-11 provides guidance on whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported on a net or gross basis and concluded such classification is a matter of judgment that depends on the relevant facts and circumstances. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called "book-out" and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We netted these book-outs reducing both revenues and purchased power and fuel costs in 2003, 2002 and 2001, but this did not impact our financial condition, net income or cash flows (see Note 18 for additional information).

#### **SunCor**

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. SunCor recognizes income only after the assets' title has passed. A single method of recognizing income is applied to all sales transactions within an entire home, land or commercial development project. Commercial property and management revenues are recorded over the term of the lease or period in which services are provided. In addition, see Note 22 – Real Estate Activities – Discontinued Operations.

#### **Percentage of Completion – NAC**

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

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

#### **Cash and Cash Equivalents**

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

#### **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 first-tier subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. See Note 4.

### Reacquired Debt Costs

For debt related to the regulated portion of APS' business, APS defers those gains and losses incurred upon early retirement and is seeking recovery in the APS general rate case (see Note 3). In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate the amortization of reacquired debt costs over an eight-year period that will end June 30, 2004. All regulatory asset amortization is included in depreciation and amortization expense in the Consolidated Statements of Income.

### Real Estate Investments

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

### Stock-Based Compensation

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

The following chart compares our net income, stock compensation expense and earnings per share to what those items would have been if we had recorded stock compensation expense based on the fair value method for all stock grants through 2003 (dollars in thousands, except per share amounts):

Year Ended December 31,	2003	2002	2001
Net Income as reported:	\$240,579	\$ 149,408	\$ 312,166
Add: Stock compensation expense included in reported net income (net of tax)	1,288	300	–
Deduct: Total stock compensation expense determined under fair value method (net of tax)	(2,994)	(1,695)	(2,292)
Pro forma net income	\$238,873	\$148,013	\$ 309,874
Earnings per share – basic:			
As reported	\$ 2.64	\$ 1.76	\$ 3.68
Pro forma (fair value method)	\$ 2.62	\$ 1.74	\$ 3.66
Earnings per share – diluted:			
As reported	\$ 2.63	\$ 1.76	\$ 3.68
Pro forma (fair value method)	\$ 2.61	\$ 1.74	\$ 3.65

In order to calculate the fair value of the 2003, 2002 and 2001 stock option grants and the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

Year Ended December 31,	2003	2002	2001
Risk-free interest rate	3.35%	4.17%	4.08%
Dividend yield	5.26%	4.17%	3.70%
Volatility	38.03%	22.59%	27.66%
Expected life (months)	60	60	60

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

### Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets on our Consolidated Balance Sheets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." The intangible assets are amortized over their finite useful lives. The Company's gross intangible assets (which are primarily capitalized software costs) were \$237 million at December 31, 2003 and \$214 million at December 31, 2002. The related accumulated amortization was \$128 million at December 31, 2003 and \$104 million at December 31, 2002. Amortization expense was \$25 million in 2003, \$21 million in 2002, and \$22 million in 2001. Estimated amortization expense on existing intangible assets over the next five years is \$28 million in 2004, \$27 million in 2005, \$25 million in 2006, \$20 million

in 2007, and \$9 million in 2008. At December 31, 2003, the weighted average amortization period for intangible assets is 7 years.

## 2. ACCOUNTING MATTERS

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

- Note 8 for amended disclosure requirements (SFAS No. 132) on retirement plans and other benefits;
- Note 12 for a new accounting standard (SFAS No. 143) on asset retirement obligations;
- Note 16 for a new accounting standard (SFAS No. 148) related to stock-based compensation;
- Note 18 for EITF issues (EITF 02-3 and 03-11), DIG Issue No. C15, and a new accounting standard (SFAS No. 149) related to accounting for derivatives and energy contracts;
- Note 20 for a new FASB interpretation (FIN No. 46R) related to VIEs;
- Note 21 for a new FASB interpretation (FIN No. 45) on guarantees; and
- Note 22 for a standard (SFAS No. 144) on accounting for the impairment or disposal of long-lived assets.

## 3. REGULATORY MATTERS

### Electric Industry Restructuring

#### State

**1999 Settlement Agreement** The following are the major provisions of the 1999 Settlement Agreement, as approved by the ACC:

- APS has reduced rates for standard-offer service for customers with loads less than three MW in a series of annual retail electricity price reductions of 1.5% on July 1 for each of the years 1999 to 2003 for a total of 7.5%. Based on the price reductions authorized in the 1999 Settlement Agreement, there were retail price decreases of approximately \$24 million (\$14 million after taxes), effective July 1, 1999; approximately \$28 million (\$17 million after taxes), effective July 1, 2000; approximately \$27 million (\$16 million after taxes), effective July 1, 2001; approximately \$28 million (\$17 million after taxes), effective July 1, 2002; and approximately \$29 million (\$18 million after taxes), effective July 1, 2003. For customers having loads of three MW or greater, standard-offer rates have been reduced in varying annual increments that total 5% in the years 1999 through 2002.
- Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.
- There is a moratorium on retail price changes for standard-offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor APS is prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders.
- APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the Rules, system benefits costs in excess of the levels included in then-current (1999) rates, and costs associated with the "provider of last resort" and standard-offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" below.
- APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the Rules (see "Retail Electric Competition Rules" below), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001. The regulatory developments and legal challenges to the Rules discussed in this Note have raised considerable uncertainty about the status and pace of electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.
- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that APS has demonstrated that its allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least \$533 million net present value (in 1999 dollars). The 1999 Settlement Agreement also states that APS will not be allowed to recover \$183 million net present value (in 1999 dollars) of the \$533 million. The 1999 Settlement Agreement provides that APS will have the opportunity to recover \$350 million net present value (in 1999 dollars) through a competitive transition charge that will remain in effect through December 31,

2004, at which time it will terminate. The costs subject to recovery under the adjustment clause described above will be decreased or increased by any over/under-recovery of the \$350 million due to sales volume variances. As discussed below under “APS General Rate Case and Retail Rate Adjustment Mechanisms,” APS is seeking to recover amounts written off by APS as a result of the 1999 Settlement Agreement.

- The 1999 Settlement Agreement required APS to form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) its competitive electric assets and services no later than December 31, 2002. The 1999 Settlement Agreement provided that APS would be allowed to defer and later collect, beginning July 1, 2004, 67% of its costs to accomplish the required transfer of generation assets to an affiliate. However, as discussed below, in 2002 the ACC unilaterally modified this aspect of the 1999 Settlement Agreement by issuing the Track A Order, an order preventing APS from transferring its generation assets. APS is seeking to recover all costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy. See “APS General Rate Case and Retail Rate Adjustment Mechanisms” below.

**Retail Electric Competition Rules** The Rules approved by the ACC include the following major provisions:

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

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot

be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement.

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

**Provider of Last Resort Obligation** Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is, under the Rules, the “provider of last resort” for standard-offer, full-service customers under rates that have been approved by the ACC. These rates are established until at least July 1, 2004. The 1999 Settlement Agreement allows APS to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders. Energy prices in the western wholesale market vary and, during the course of the last two years, have been volatile. At various times, prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain an adjustment of its rates under the emergency provisions of the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power. See “APS General Rate Case and Retail Rate Adjustment Mechanisms” below for a discussion of retail rate adjustment mechanisms that were the subject of ACC hearings in April 2003.

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

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

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

- APS and the ACC staff agreed that it would be appropriate for the ACC to consider the following matters in APS' general rate case, which was filed on June 27, 2003:
  - the generating assets to be included in APS' rate base, including the question of whether the PWEC Dedicated Assets should be included in APS' rate base;
  - the appropriate treatment of the \$234 million pretax asset write-off agreed to by APS as part of the 1999 Settlement Agreement; and
  - the appropriate treatment of costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy.
- Upon the ACC's issuance of a final decision that is no longer subject to appeal approving APS' request to provide \$500 million of financing or credit support to Pinnacle West Energy or the Company, with appropriate conditions, APS' appeals of the Track A Order would be limited to the issues described in the preceding bullet points, each of which would be presented to the ACC for consideration prior to any final judicial resolution. As noted below, the ACC issued the Financing Order on April 4, 2003. The Financing Order is final and no longer subject to appeal. As a result, APS' appeals of the Track A Order are limited to the issues described in the preceding bullet points.

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

**Track B Order** On March 14, 2003, the ACC issued the Track B Order, which required APS to solicit bids for certain estimated amounts of capacity and energy for periods beginning July 1, 2003. For 2003, APS was required to solicit competitive bids for about 2,500 MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of APS' total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in APS' retail load and APS' retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets."

The order recognizes APS' right to reject any bids that are unreasonable, uneconomical or unreliable. The ACC staff and an independent monitor participated in the Track B procurement process. The Track B Order also contains requirements relating to standards of conduct between APS and any affiliate of APS participating in the competitive solicitation, requires that APS treat bidders in a non-discriminatory manner and requires APS to file a protocol regarding short-term and emergency procurements. The order permits the provision by APS of corporate oversight, support and governance as long as such activities do not favor Pinnacle West Energy in the procurement process or provide Pinnacle West Energy with confidential APS bidding information that is not available to other bidders. The order directs APS to evaluate bids on cost, reliability and reasonableness. The decision requires bidders to allow the ACC to inspect their plants and requires assurances of appropriate competitive market conduct from senior officers of such bidders. Following the solicitation, the decision requires APS to prepare a report evaluating environmental issues relating to the procurement, and a series of workshops on environmental risk management will be commenced thereafter.

APS issued requests for proposals in March 2003 and, by May 6, 2003, APS entered into contracts to meet all or a portion of its requirements for the years 2003 through 2006 as follows:

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

**ACC Financing Orders** On April 4, 2003, the ACC issued the Financing Order authorizing APS to lend up to \$500 million to Pinnacle West Energy, guarantee up to \$500 million of Pinnacle West Energy debt, or a combination of both, not to exceed \$500 million in the aggregate (the “APS Loan”), subject to the following principal conditions:

- any debt issued by APS pursuant to the order must be unsecured;
- the APS Loan must be callable and secured by the PWEC Dedicated Assets;
- the APS Loan must bear interest at a rate equal to 264 basis points above the interest rate on APS debt that could be issued and sold on equivalent terms (including, but not limited to, maturity and security);
- the 264 basis points referred to in the previous bullet point will be capitalized as a deferred credit and used to offset retail rates in the future, with the deferred credit balance bearing an interest rate of six percent per annum;
- the APS Loan must have a maturity date of not more than four years, unless otherwise ordered by the ACC;
- any demonstrable increase in APS' cost of capital as a result of the transaction (such as from a decline in bond rating) will be excluded from future rate cases;
- APS must maintain a common equity ratio of at least forty percent and may not pay common dividends if such payment would reduce its common equity ratio below that threshold, unless otherwise waived by the ACC. The ACC will process any waiver request within sixty days, and for this sixty-day period this condition will be suspended. However, this condition, which will continue indefinitely, will not be permanently waived without an order of the ACC; and
- certain waivers of the ACC's affiliated interest rules previously granted to APS and its affiliates will be temporarily withdrawn and, during the term of the APS Loan, neither Pinnacle West nor Pinnacle West Energy may reorganize or restructure, acquire or divest assets, or form, buy or sell affiliates (each, a “Covered Transaction”), or pledge or otherwise encumber the Pinnacle West Energy assets without prior ACC approval, except that the foregoing restrictions will not apply to the following categories of Covered Transactions:
  - Covered Transactions less than \$100 million, measured on a cumulative basis over the calendar year in which the Covered Transactions are made;
  - Covered Transactions by SunCor of less than \$300 million through 2005, consistent with SunCor's anticipated accelerated asset sales activity during those years;

- Covered Transactions related to the payment of ongoing construction costs for Pinnacle West Energy's (a) West Phoenix Unit 5, located in Phoenix, and (b) Silverhawk plant, located near Las Vegas, with an expected commercial operation date in mid-2004; and
- Covered Transactions related to the sale of 25% of the Silverhawk plant to SNWA pursuant to an agreement between SNWA and Pinnacle West Energy.

The ACC also ordered the ACC staff to conduct an inquiry into our and our affiliates' compliance with the retail electric competition and related rules and decisions. On June 13, 2003, APS submitted its report on these matters to the ACC staff. The ACC has indicated that the preliminary investigation would be addressed in the pending general rate case (see below).

On May 12, 2003, APS issued \$500 million of debt pursuant to the Financing Order and made a \$500 million loan to Pinnacle West Energy. Pinnacle West Energy distributed the net proceeds of that loan to us to fund the repayment of a portion of the debt we incurred to finance the construction of the PWEC Dedicated Assets. See Note 6.

On November 22, 2002, the ACC issued an order approving APS' request to permit APS to make short-term advances to Pinnacle West in the form of an interaffiliate line of credit in the amount of \$125 million. As of December 31, 2003, there were no borrowings outstanding under this financing arrangement, and this authority expired on December 4, 2003.

**APS General Rate Case and Retail Rate Adjustment Mechanisms** As noted above, on June 27, 2003, APS filed a general rate case with the ACC and requested a \$175.1 million, or 9.8%, increase in its annual retail electricity revenues, to become effective July 1, 2004. In this rate case, APS updated its cost of service and rate design.

**Major Components of the Request** The major reasons for the request include:

- complying with the provisions of the 1999 Settlement Agreement;
- incorporating significant increases in fuel and purchased power costs, including results of purchases through the ACC's Track B procurement process;
- recognizing changes in APS' cost of service, cost allocation and rate design;
- obtaining rate recognition of the PWEC Dedicated Assets;
- recovering \$234 million written off by APS as a result of the 1999 Settlement Agreement; and

- recovering restructuring and compliance costs associated with the ACC's Rules.

**Requested Rate Increase** The requested rate increase totals \$175.1 million, or 9.8%, and is comprised of the following items (dollars in millions):

	Annual Revenue	Percent
Increase in base rates	\$ 166.8	9.3%
Rules compliance charge	8.3	0.5%
Total increase	\$ 175.1	9.8%

**Test Year** The filing is based on an adjusted historical test year ended December 31, 2002.

**Cost of Capital** The proposed weighted average cost of capital for the test year ended December 31, 2002 is 8.67%, including an 11.5% return on equity.

**Rate Base** The request is based on a rate base of \$4.2 billion, calculated using Original Cost Less Depreciation ("OCLD") methodology. The OCLD rate base approximates the ACC-jurisdictional portion of the net book value of utility plant, net of accumulated depreciation and deferred taxes, as of December 31, 2002, except as set forth below.

The requested rate base includes the PWEC Dedicated Assets, with a total combined capacity of approximately 1,800 MW. These assets were included at their estimated July 1, 2004 net book value. Upon approval of the request, the PWEC Dedicated Assets would be transferred to APS from Pinnacle West Energy.

The filing also includes calculated amounts for Fair Value Rate Base and Replacement Cost New Depreciated ("RCND") rate base. The ACC is required by the Arizona Constitution to make a finding of Fair Value Rate Base, which has traditionally been defined by the ACC as the arithmetic average of OCLD rate base and RCND rate base.

**Recovery of Previous \$234 Million Write-Off** The request includes recovery, over a fifteen year period, of the write-off of \$234 million pretax of regulatory assets by APS as a result of the 1999 Settlement Agreement. See "1999 Settlement Agreement" above.

**Estimated Timeline** APS has asked the ACC to approve the requested rate increase by July 1, 2004. The ACC ALJ has issued a procedural schedule setting a hearing date on the application of May 25, 2004. Based on the schedule and existing ACC regulations, we believe the ACC will be able to make a decision in this general rate case by the end of 2004.

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

On November 4, 2003, the ACC approved the issuance of an order which authorizes a rate adjustment mechanism allowing APS to recover changes in purchased power costs (but not changes in fuel costs) incurred after July 1, 2004. The other rate adjustment mechanisms authorized in the 1999 Settlement Agreement (such as the costs associated with complying with the ACC electric competition rules) were also tentatively approved for subsequent implementation in the general rate case. The provisions of this order will not become effective until there is a final order in the general rate case, and the ACC further reserved the right to amend, modify or reconsider, in its entirety, this November 4 order during the rate case.

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

- the ACC "litigation" staff;
- the Arizona Residential Utility Consumers Office ("RUCO"), an office established by the Arizona legislature to represent the interests of residential utility consumers before the ACC; and
- other approved rate case interveners.

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

- decrease APS' annual retail electricity revenues by at least \$142.7 million, which would result in a rate decrease of approximately 8%, based on a 9% return on equity;
- not allow the PWEC Dedicated Assets to be included in APS' rate base;
- not allow APS to recover any of the \$234 million written off as a result of the 1999 Settlement Agreement; and
- not implement any adjustment mechanisms for fuel and purchased power.

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

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

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

- decrease APS’ annual retail electricity revenues by \$53.6 million, which would result in a rate decrease of approximately 2.84%, based on a 9.5% return on equity;
- not allow the PWEC Dedicated Assets to be included in APS’ rate base;
- not allow APS to recover any of the \$234 million written off as a result of the 1999 Settlement Agreement; and
- not implement any adjustment mechanisms for fuel and purchased power.

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

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

**Federal**

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

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

**General**

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

**4. INCOME TAXES**

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

APS has recorded a regulatory asset related to income taxes on its Balance Sheets in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. APS amortizes this amount as the differences reverse. In accordance with ACC settlement agreements, APS is continuing to accelerate amortization of a regulatory asset related to income taxes over an eight-year period that will end June 30, 2004 (see Note 1). Accordingly, we are including this accelerated amortization in depreciation and amortization expense on our Consolidated Statements of Income.

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. In 2003, we resolved certain prior-year issues with the taxing authorities and recorded an \$18 million tax benefit associated with tax credits and other reductions to income tax expense.

The components of income tax expense for income from continuing operations are as follows (dollars in thousands):

Year Ended December 31,	2003	2002	2001
Current:			
Federal	\$ 22,875	\$ (43,492)	\$ 184,893
State	929	(15,415)	45,845
Total current	23,804	(58,907)	230,738
Deferred	81,756	191,135	(17,203)
Total income tax expense	\$ 105,560	\$ 132,228	\$ 213,535

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

Year Ended December 31,	2003	2002	2001
Federal income tax expense			
at 35% statutory rate	\$ 117,648	\$ 118,449	\$ 189,316
Increases (reductions)			
in tax expense			
resulting from:			
State income tax net			
of federal income			
tax benefit	14,353	15,796	23,353
Credits and favorable			
adjustments related to			
prior years resolved			
in 2003	(17,944)	-	-
Allowance for equity funds			
used during construction			
(see Note 1)	(5,616)	-	-
Other	(2,881)	(2,017)	866
Income tax expense	\$ 105,560	\$ 132,228	\$ 213,535

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

December 31,	2003	2002
Current asset/(liability)	\$ (631)	\$ 4,094
Long term liability	(1,329,253)	(1,209,074)
Accumulated deferred income		
taxes – net	\$ (1,329,884)	\$ (1,204,980)

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

December 31,	2003	2002
<b>DEFERRED TAX ASSETS</b>		
Pension liability	\$ 73,844	\$ 72,835
Risk management and		
trading activities	59,293	43,542
Regulatory liabilities:		
Federal excess deferred		
income taxes	18,936	20,887
Other	33,542	9,818
Deferred gain on Palo Verde		
Unit 2 sale leaseback	21,656	23,562
Other	64,769	89,236
Total deferred tax assets	272,040	259,880
<b>DEFERRED TAX LIABILITIES</b>		
Plant-related	(1,448,730)	(1,316,636)
Regulatory assets	(69,070)	(101,522)
Risk management and		
trading activities	(84,124)	(46,702)
Total deferred tax liabilities	(1,601,924)	(1,464,860)
Accumulated deferred		
income taxes – net	\$ (1,329,884)	\$ (1,204,980)

## 5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

APS had committed lines of credit with various banks of \$250 million at December 31, 2003 and 2002, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The current line matures in May 2004, and the document allows for a 364-day extension of the termination date without lender consent. The commitment fees at December 31, 2003 and 2002 for these lines of credit were 0.175% and 0.09% per annum. APS had no bank borrowings outstanding under these lines of credit at December 31, 2003 and 2002.

APS had no commercial paper borrowings outstanding at December 31, 2003 and 2002. By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

Pinnacle West had committed lines of credit of \$275 million at December 31, 2003 and \$475 million at December 31, 2002, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The current lines mature in November and December of 2004 and the \$150 million facility allows for a 364-day extension of the termination date without lender consent. Pinnacle West had no outstanding borrowings at December 31, 2003 and \$72 million was outstanding at December 31, 2002. The commitment fees ranged from 0.125% to 0.175% in 2003 and ranged from 0.10% to 0.15% in 2002. Pinnacle West had no commercial paper borrowings outstanding at December 31, 2003. Commercial paper borrowings outstanding were \$24 million at December 31, 2002. The weighted average interest rate on commercial paper borrowings was 2.06% for the year ended December 31, 2002.

All APS and Pinnacle West bank lines of credit and commercial paper agreements are unsecured.

On November 22, 2002, the ACC approved APS' request to permit APS to make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of \$125 million. This interim loan matured in December 2003, and there were never any borrowings on this line.

SunCor had revolving lines of credit totaling \$120 million at December 31, 2003 and \$140 million at December 31, 2002. The commitment fees were 0.125% in 2003 and 2002. SunCor had \$50 million outstanding at December 31, 2003 and \$126 million outstanding at December 31, 2002. The weighted-average interest rate was 4.50% at December 31, 2003 and was 3.75% at December 31, 2002. Interest for 2003 and 2002 was based on LIBOR plus 2% or prime plus 0.5%. The balance is included in short-term debt on the Consolidated Balance Sheets. SunCor had other short-term loans in the amount of \$36 million at December 31, 2003 and \$6 million outstanding at December 31, 2002. These loans are made up of multiple notes primarily with variable interest rates based on LIBOR plus 2.5% at December 31, 2003 and 2002. In addition, two notes acquired in 2003 had interest rates of 3.37% and 3.87%.

## 6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plant. APS also has unsecured debt. 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, 2003 and 2002 (dollars in thousands):

December 31,	Maturity Dates (a)	Interest Rates	2003	2002
<b>APS</b>				
First mortgage bonds	2004	6.625%	\$ 80,000	\$ 80,000
	2023	7.25% (b)	–	54,150
	2025	8.0% (c)	–	33,075
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(8,631)	(6,337)
Pollution control bonds	2024-2034	(d)	386,860	386,860
Pollution control bonds with senior notes (e)	2029	5.05%	90,000	90,000
Unsecured notes	2004	5.875%	125,000	125,000
Unsecured notes	2005	6.25%	100,000	100,000
Unsecured notes	2005	7.625%	300,000	300,000
Unsecured notes	2011	6.375%	400,000	400,000
Unsecured notes	2012	6.50%	375,000	375,000
Unsecured notes	2033	5.625%	200,000	–
Unsecured notes	2015	4.650%	300,000	–
Senior notes (f)	2006	6.75%	83,695	83,695
Capitalized lease obligations	2004-2012	(g)	11,749	20,400
Subtotal			<u>2,622,673</u>	<u>2,220,843</u>
<b>SUNCOR</b>				
Notes payable	2004-2008	(h)	17,125	7,647
Capitalized lease obligations	2004-2005	8.91%	728	1,299
Subtotal			<u>17,853</u>	<u>8,946</u>
<b>PINNACLE WEST</b>				
Senior notes	2004-2006	(i)	515,000	540,000
Unamortized discount and premium			(270)	(530)
Floating rate notes	2003	(j)	–	250,000
Floating senior notes	2005	(k)	165,000	–
Capitalized lease obligations	2004-2007	5.48%	1,243	1,999
Subtotal			<u>680,973</u>	<u>791,469</u>
<b>EL DORADO</b>				
Construction loan	2005	1.22%	1,600	2,600
Capitalized lease obligations	2004-2005	(l)	106	771
Subtotal			<u>1,706</u>	<u>3,371</u>
Total long-term debt			<u>3,323,205</u>	<u>3,024,629</u>
Less current maturities			<u>425,480</u>	<u>280,888</u>
<b>TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES</b>			<u>\$ 2,897,725</u>	<u>\$ 2,743,741</u>

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

(b) On August 15, 2003, APS redeemed at maturity \$54 million of its First Mortgage Bonds, 7.25% Series due 2023.

(c) On April 7, 2003, APS redeemed \$33 million of its First Mortgage Bonds, 8.00% Series due 2025.

(d) The weighted-average rate was 1.51% at December 31, 2003 and 1.94% at December 31, 2002. Changes in short-term interest rates would affect the costs associated with this debt.

(e) On November 1, 2002, Maricopa County, Arizona Pollution Control Corporation issued \$90 million of 5.05% Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Palo Verde Project) 2002 Series A, due 2029, and loaned the proceeds to APS pursuant to a loan agreement. The bonds were issued to refinance \$90 million of outstanding pollution control bonds. The bondholders were issued \$90 million of first mortgage bonds (senior note mortgage bonds) as collateral.

(f) APS currently has outstanding \$84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes, as well as the \$90 million issue discussed in footnote (e) above. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity and redemption provisions as the senior notes. APS' payments of principal, premium and/or interest on the senior notes satisfy its corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. When APS repays all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.

- (g) The weighted average rate was 5.55% at December 31, 2003 and 5.78% at December 31, 2002. Capital leases are included in property, plant and equipment on the Consolidated Balance Sheets for both December 31, 2003 and December 31, 2002.
- (h) Multiple notes with variable interest rates based on the lenders' prime plus 0.25%, lenders' prime plus 1.75% and LIBOR plus 2.5%. There is also one note at a fixed rate of 7.96%.
- (i) Includes two series of notes: \$300 million at 6.4% due in 2006 and \$215 million at 4.5% due in 2004 as of December 31, 2002. In December 2003, we repaid the \$25 million note. On January 29, 2004, we entered into a fixed-for-floating interest rate swap transaction on the \$300 million 6.4% note. The transaction qualifies as a fair value hedge under SFAS No. 133.
- (j) The weighted average rate was 2.85% at December 31, 2002. Interest for 2002 was based on LIBOR plus 0.98%. In June 2003, we repaid the \$250 million floating note.
- (k) The weighted average rate was 1.980% at December 31, 2003. Interest for 2003 was based on LIBOR plus 0.80%.
- (l) The weighted average rate was 7.9% at December 31, 2003 and 7.04% at December 31, 2002.

Pinnacle West's and APS' debt covenants related to their respective financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS comply with these covenants and each anticipates it will continue to meet the covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65% for each of the Company and APS individually. At December 31, 2003, the ratio was approximately 54% for Pinnacle West. At December 31, 2003, the ratio was approximately 53% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for each of the Company and APS. Based on 2003 results, the coverages were approximately 4 times for the Company, 4 times for the APS bank agreements and 15 times for the APS mortgage indenture. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

Neither Pinnacle West's nor APS' financing agreements contain "ratings triggers" that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a ratings downgrade, Pinnacle West and/or APS may be subject to increased interest costs under certain financing agreements.

All of Pinnacle West's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under other agreements. All of APS' bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under other agreements. Pinnacle West's and APS' credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in our financial condition or financial prospects.

The following is a list of payments due on total long-term debt and capitalized lease requirements through 2008:

- \$425 million in 2004;
- \$569 million in 2005;
- \$395 million in 2006;
- \$2 million in 2007;
- \$6 million in 2008; and
- \$1,935 million, thereafter.

APS' first mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment and other excluded assets). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. APS may pay dividends on its common stock if there is a sufficient amount "available" from retained earnings and the excess of cumulative book depreciation (since the mortgage's inception) over mortgage depreciation, which is the cumulative amount of additional property pledged each year to address collateral depreciation. As of December 31, 2003, the amount "available" under the mortgage would have allowed APS to pay approximately \$3 billion of dividends compared to APS' current annual common stock dividends of \$170 million.

The mortgage currently constitutes a lien on substantially all of the property of APS. We anticipate that in early April 2004, all first mortgage bonds issued by APS under its existing mortgage and deed of trust, other than the first mortgage bonds securing APS' senior notes, will have been paid and retired. At that time, APS' obligation to make payment on the first mortgage bonds securing the senior notes will also be deemed to be satisfied and discharged and the senior note first mortgage bonds will cease to secure the senior notes. APS is then obligated to take all steps necessary to terminate its existing mortgage and deed of trust and cannot issue any additional first mortgage bonds under that mortgage.

## 7. COMMON STOCK AND TREASURY STOCK

Our common stock and treasury stock activity during each of the three years 2003, 2002 and 2001 is as follows (dollars in thousands):

	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount
Balance at December 31, 2000	84,824,947	\$ 1,537,920	(109,638)	\$ (5,089)
Purchase of treasury stock	–	–	(334,600)	(16,393)
Reissuance of treasury stock for stock compensation (net)	–	–	342,931	15,596
Other	–	(996)	–	–
Balance at December 31, 2001	84,824,947	1,536,924	(101,307)	(5,886)
Common stock issuance – December 23, 2002	6,555,000	199,238	–	–
Purchase of treasury stock	–	–	(150,500)	(5,971)
Reissuance of treasury stock for stock compensation (net)	–	–	126,977	7,499
Other	–	1,096	–	–
Balance at December 31, 2002	91,379,947	1,737,258	(124,830)	(4,358)
Reissuance of treasury stock for stock compensation (net)	–	–	32,815	1,085
Other	–	7,096	–	–
Balance at December 31, 2003	91,379,947	\$ 1,744,354	(92,015)	\$ (3,273)

## 8. RETIREMENT PLANS AND OTHER BENEFITS

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

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

Pinnacle West also sponsors other postretirement benefits for the employees of Pinnacle West and our subsidiaries. We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which

are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

In December 2003, FASB revised SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," to enhance disclosures of relevant accounting information by providing additional information on plan assets, obligations, cash flows, and net cost. The revisions are reflected in this Note. Pinnacle West uses a December 31 measurement date for its plans.

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

The following table provides details of the plan's 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		
	2003	2002	2001	2003	2002	2001
Service cost – benefits earned during the period	\$ 37,662	\$ 30,333	\$ 27,640	\$ 15,858	\$ 12,036	\$ 9,438
Interest cost on benefit obligation	76,951	71,242	66,549	30,163	25,235	21,585
Expected return on plan assets	(65,046)	(75,652)	(77,340)	(18,762)	(21,116)	(21,985)
Amortization of:						
Transition (asset)/obligation	(3,227)	(3,227)	(3,227)	3,005	4,001	7,698
Prior service cost/(credit)	2,401	2,912	3,008	(125)	(75)	–
Net actuarial loss/(gain)	18,135	1,846	907	9,714	3,072	(4,066)
Net periodic benefit cost	\$ 66,876	\$ 27,454	\$ 17,537	\$ 39,853	\$ 23,153	\$ 12,670
Portion of cost charged to expense	\$ 30,094	\$ 13,727	\$ 8,944	\$ 17,934	\$ 11,577	\$ 6,462

The following table sets forth the plan's change in the benefit obligations for the plan years 2003 and 2002 (dollars in thousands):

Year Ended December 31,	Pension		Other Benefits	
	2003	2002	2003	2002
Benefit obligation at January 1	\$ 1,069,577	\$ 931,646	\$ 409,874	\$ 318,355
Service cost	37,662	30,333	15,858	12,036
Interest cost	76,951	71,242	30,163	25,235
Benefit payments	(43,869)	(35,230)	(15,749)	(10,473)
Actuarial losses	171,420	71,696	106,475	108,979
Plan amendments	(4,113)	(110)	(6,440)	(44,258)(a)
Benefit obligation at December 31	\$ 1,307,628	\$ 1,069,577	\$ 540,181	\$ 409,874

(a) The plan was amended in January 2002 to increase the deductibles, out-of-pocket maximums and prescription drug co-pays. The plan was amended in June 2002 to increase the participants' portion of premiums.

The following table sets forth the qualified defined benefit plan and other benefit plan changes in the fair value of plan assets for the years 2003 and 2002 (dollars in thousands):

Year Ended December 31,	Pension		Other Benefits	
	2003	2002	2003	2002
Fair value of plan assets at January 1	\$ 720,807	\$ 764,873	\$ 223,474	\$ 237,810
Actual gain/(loss) on plan assets	162,571	(36,966)	46,071	(27,802)
Employer contributions	46,000	26,600	39,852	23,600
Benefit payments	(42,067)	(33,700)	(15,346)	(10,134)
Fair value of plan assets at December 31	\$ 887,311	\$ 720,807	\$ 294,051	\$ 223,474

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in the Consolidated Balance Sheets as of December 31, 2003 and 2002 (dollars in thousands):

December 31,	Pension		Other Benefits	
	2003	2002	2003	2002
Funded status at December 31	\$ (420,317)	\$ (348,770)	\$ (246,130)	\$ (186,400)
Unrecognized net transition (asset)/obligation	(7,099)	(10,327)	27,044	36,489
Unrecognized prior service cost/(credit)	16,634	23,148	(1,547)	(1,673)
Unrecognized net actuarial losses/(gains)	348,982	293,223	217,611	148,268
Benefit liability recognized in the Consolidated Balance Sheet	\$ (61,800)	\$ (42,726)	\$ (3,022)	\$ (3,316)

The following sets forth the details related to benefits included on the Consolidated Balance Sheets (dollars in thousands):

December 31,	Pension		Other Benefits	
	2003	2002	2003	2002
Accrued benefit cost	\$ (61,800)	\$ (42,726)	\$ (3,022)	\$ (3,316)
Additional minimum liability	(126,241)	(141,154)	-	-
Total liability	(188,041)	(183,880)	(3,022)	(3,316)
Intangible asset	16,634	23,147	-	-
Accumulated other comprehensive income (pretax)	109,607	118,007	-	-
Net amount recognized	\$ (61,800)	\$ (42,726)	\$ (3,022)	\$ (3,316)

The following table sets forth the other comprehensive income arising from the change in additional minimum liability for the years ended December 31, 2003 and 2002 (dollars in thousands):

Year Ended December 31,	2003	2002
Decrease/(Increase) in minimum liability included in other comprehensive income – net of tax	\$ 4,700	\$ (70,298)

The following table sets forth the projected benefit obligation and the accumulated benefit obligation for pension plans in excess of plan assets for the plan years 2003 and 2002 (dollars in thousands):

Year Ended December 31,	2003	2002
Projected benefit obligation	\$ 1,307,628	\$ 1,069,577
Accumulated benefit obligation	\$ 1,075,352	\$ 904,687
Less fair value of plan assets	887,311	720,807
Pension liability	\$ 188,041	\$ 183,880

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

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,	
	2003	2002	2003	2002
Discount rate	6.10%	6.75%	6.75%	7.50%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	10.00%
Initial health care cost trend rate	8.00%	8.00%	8.00%	7.00%
Ultimate health care cost trend rate	5.00%	5.00%	5.00%	5.00%
Year ultimate health care cost trend rate is reached	2008	2007	2007	2006

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 2003, we decreased our pretax expected long-term rate of return on plan assets from 10% to 9%, as a result of continued declines in general equity and bond market conditions. For the year 2004 we are assuming a 9% rate of return on plan assets. This rate is reflective of the market returns earned historically on our target asset allocation. As recent history has demonstrated, markets may decline and increase dramatically. However, the long-term rate of return on plan assets of 9% is reasonable given our asset allocation in relation to historical and expected future performance.

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

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	\$ 7	\$ (5)
Effect on service and interest cost components of net periodic other postretirement benefit costs	\$ 9	\$ (7)
Effect on the accumulated other postretirement benefit obligation	\$ 95	\$ (76)

#### Plan Assets

Pinnacle West's qualified pension plan asset allocation at December 31, 2003, and 2002 is as follows:

Asset Category:	Percentage of Plan Assets at December 31,		Target Asset Allocation
	2003	2002	
Equity securities	65%	56%	50 – 70%
Debt securities	23	31	20 – 40%
Other	12	13	5 – 15%
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 a stated tolerance 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 plan asset allocation at December 31, 2003, and 2002, is as follows:

Asset Category:	Percentage of Plan Assets at December 31,		Target Asset Allocation
	2003	2002	
Equity securities	71%	62%	60 – 80%
Fixed Income	25	34	20 – 35%
Other	4	4	1 – 6%
Total	100%	100%	

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

#### Contributions

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

#### Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and subsidiaries. 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, 2003, approximately 23% of total plan assets were in Pinnacle West stock. We recorded expenses for this plan of approximately \$5 million for each of the years 2003, 2002 and 2001.

#### Severance Charges

In July 2002, we implemented a voluntary workforce reduction as part of our cost reduction program. We recorded \$36 million before taxes in voluntary severance costs in 2002. No further charges are expected.

#### 9. LEASES

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

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

Total lease expense recognized in the Consolidated Statements of Income was \$67 million in 2003, \$67 million in 2002 and \$59 million in 2001.

The amounts to be paid for the Palo Verde Unit 2 leases are approximately \$49 million per year for the years 2004 to 2015.

In accordance with the 1999 Settlement Agreement and previous settlement agreements, APS is continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004 (see Note 1). All regulatory asset amortization is included in depreciation and amortization expense in the Consolidated Statements of Income. The balance of this regulatory asset at December 31, 2003 was \$5 million.

Estimated future minimum lease payments for our operating leases are approximately as follows (dollars in millions):

Year		
2004	\$	73
2005		70
2006		68
2007		66
2008		66
Thereafter		421
Total future lease commitments	\$	764

#### 10. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. The following table shows APS' interest in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2003. APS' share of operating and maintaining these facilities is included in the Consolidated Statements of Income in operations and maintenance expense (dollars in thousands):

	Percent Owned by APS	Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	\$ 1,880,218	\$ (867,322)	\$ 21,620
Palo Verde Nuclear Generating Station Unit 2 (see Note 9)	17.0%	681,744	(242,131)	9,771
Four Corners Steam Generating Station Units 4 and 5	15.0%	154,111	(81,369)	2,580
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	242,987	(111,744)	2,352
Cholla Steam Generating Station Common Facilities (a)	62.4%(b)	78,500	(44,379)	1,338
Transmission Facilities:				
ANPP 500KV System	35.8%(b)	68,457	(27,050)	40
Navajo Southern System	31.4%(b)	26,903	(17,971)	128
Palo Verde – Yuma 500KV System	23.9%(b)	9,583	(4,364)	602
Four Corners Switchyards	27.5%(b)	2,852	(1,734)	–
Phoenix – Mead System	17.1%(b)	36,418	(3,567)	–
Palo Verde – Estrella 500KV System	55.5%(b)	70,972	(1,615)	1,632
Palo Verde SE Valley Project	15.0%(b)	–	–	648

(a) PacifiCorp owns Cholla Unit 4 and APS operates the unit for PacifiCorp. The common facilities at the Cholla Plant are jointly-owned.

(b) Weighted average of interests.

## 11. COMMITMENTS AND CONTINGENCIES

### Enron

We recorded charges totaling \$21 million before income taxes for exposure to Enron and its affiliates in the fourth quarter of 2001. This amount is comprised of a \$15 million reserve for the Company's net exposure to Enron and its affiliates and additional expenses of \$6 million primarily related to 2002 power contracts with Enron that were canceled. These charges take into consideration our rights of set-off with respect to the Enron related contractual obligations. The APS portion of the write-off was \$13 million. The basis of the set-offs included, but was not limited to, provisions in the various contractual arrangements with Enron and its affiliates, including an International Swaps and Derivative Agreement (ISDA) between APS and Enron North America. The write-off is also net of the expected recovery based on secondary market quotes from the bond market. The amounts were written-off from the balances of the related assets and liabilities from risk management and trading activities on the Consolidated Balance Sheets. In February 2004, Enron filed an adversary proceeding against APS in bankruptcy court regarding differences in the valuation of trading positions involving APS. Enron North America v. Arizona Public Service Company, Adversary Proceeding No. 04-02366 (ALJ). APS will vigorously defend this action and does not believe it will have any material adverse impact on its anticipated exposure to Enron described above.

### Palo Verde Nuclear Generating Station

#### *Spent Fuel and Waste Disposal*

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

In February 2002, the Secretary of Energy recommended to President Bush that the Yucca Mountain, Nevada site be developed as a permanent repository for spent nuclear fuel. The President transmitted this recommendation to Congress and the State of Nevada vetoed the President's recommendation. Congress

approved the Yucca Mountain site, overriding the Nevada veto. It is now expected that the DOE will submit a license application to the NRC in late 2004. The State of Nevada has filed several lawsuits relating to the Yucca Mountain site. We cannot currently predict what further steps will be taken in this area.

APS has existing fuel storage pools at Palo Verde and is operating a new facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, APS believes spent nuclear fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Although some low-level waste has been stored on-site in a low-level waste facility, APS is currently shipping low-level waste to off-site facilities. APS currently believes interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

APS currently estimates it will incur \$115 million (in 2003 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2003, APS had spent \$7 million and recorded a liability of \$42 million for on-site interim spent nuclear fuel storage costs related to nuclear fuel burned to date. APS has recorded a corresponding regulatory asset of \$49 million and is seeking recovery of these costs through future rates (see "APS General Rate Case and Retail Rate Mechanisms" in Note 3).

APS has reclassified prior year spent nuclear fuel costs of approximately \$44 million previously included in accumulated amortization of nuclear fuel to the liability for asset retirements and removals on our Consolidated Balance Sheets at December 31, 2002. Upon adoption of SFAS No. 143 in 2003, APS reclassified this liability to a regulatory liability because no legal obligation for removal exists.

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

#### *Nuclear Insurance*

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of \$300 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS

could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately \$101 million, subject to an annual limit of \$10 million per incident. Based on APS' interest in the three Palo Verde units, APS' maximum potential assessment per incident for all three units is approximately \$88 million, with an annual payment limitation of approximately \$9 million.

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

#### Purchased Power and Fuel Commitments

APS and Pinnacle West are parties to various purchased power and fuel contracts with terms expiring from 2004 through 2025 that include required purchase provisions. We estimate the contract requirements to be approximately \$209 million in 2004; \$68 million in 2005; \$66 million in 2006; \$51 million in 2007; \$51 million in 2008 and \$461 million thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various purchased power and fuel contracts mentioned above some of those contracts have take-or-pay provisions. The contracts APS has for the supply of its coal and nuclear fuel supply have take-or-pay provisions. The current take-or-pay coal contracts have terms that expire in 2016. The current take-or-pay nuclear fuel contracts expire in 2004 and had not been renewed as of December 31, 2003.

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

Estimated Years Ending December 31,	2004	2005	2006	2007	2008	There- after
Coal	\$ 41	\$ 42	\$ 43	\$ 44	\$ 43	\$306
Nuclear	11	-	-	-	-	-
Total take-or-pay commitments (a)	\$ 52	\$ 42	\$ 43	\$ 44	\$ 43	\$306

(a) Total take-or-pay commitments are approximately \$530 million. The total net present value of these commitments is approximately \$340 million.

#### Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. Our coal mine reclamation obligation was \$60 million at December 31, 2003 and \$59 million at December 31, 2002 and is included in deferred credits-other in the Consolidated Balance Sheets.

A regulatory asset has been established for amounts not yet recovered from ratepayers related to the coal obligations. In accordance with the 1999 Settlement Agreement with the ACC, APS is continuing to accelerate the amortization of the regulatory asset for coal mine reclamation over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Consolidated Statements of Income.

#### California Energy Market Issues and Refunds in the Pacific Northwest

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

The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The FERC affirmed the ALJ's conclusion that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. This decision has now been appealed to the Court of Appeals (Ninth Circuit).

Although the FERC ruling in the Pacific Northwest matter is being appealed and the FERC has not yet calculated the specific refund amounts due in California, we do not expect that the resolution of these issues, as to the amounts alleged in the proceedings, will have a material adverse impact on our financial position, results of operations or liquidity.

On March 26, 2003, FERC made public a Final Report on Price Manipulation in Western Markets, prepared by its Staff and covering spot markets in the West in 2000 and 2001. The report stated that a significant number of entities who participated in the California markets during the 2000-2001 time period, including APS, may potentially have been involved in arbitrage transactions that allegedly violated certain provisions of the ISO tariff. APS and the FERC staff have settled this matter, and the settlement was approved by the FERC.

SCE and PG&E have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the PX and the ISO. PG&E filed for bankruptcy protection in 2001.

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. Based on our evaluations, we previously reserved \$10 million before income taxes for our credit exposure related to the California energy situation, \$5 million of which was recorded in the fourth quarter of 2000 and \$5 million of which was recorded in the first quarter of 2001. Our evaluations took into consideration our range of exposure of approximately zero to \$38 million before income taxes and a review of likely recovery rates in bankruptcy situations.

In the second quarter of 2002, PG&E filed its Modified Second Amended Disclosure Statement and the CPUC filed its Alternative Plan of Reorganization. Both plans generally indicated that PG&E would, at the close of bankruptcy proceedings, be able to pay in full all outstanding, undisputed debts. As a result of these developments, the probable range of our total exposure now is approximately zero to \$27 million before income taxes, and our best estimate of the probable loss is now approximately \$6 million before income taxes. Consequently, we reversed \$4 million of the \$10 million reserve in the second quarter of 2002. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us, our subsidiaries or the regional energy market in general.

#### **California Energy Market Litigation**

On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including the Company, failed to properly file rate information at the FERC in connection with sales to California from 2000 to the present. State of California v. British Columbia Power Exchange et al., Docket No. EL02-71-000. The complaint requests the FERC to require the wholesale sellers to refund any rates that are “found to exceed just and reasonable levels.” This complaint has been dismissed by the FERC and the State of California is now appealing the matter to the Ninth Circuit Court of Appeals. In addition, the State of California and others have filed various claims, which have now been consolidated, against several power suppliers to California alleging antitrust violations. Wholesale Electricity Antitrust Cases I and II, Superior Court in and for the County of San Diego, Proceedings Nos. 4204-00005 and 4204-00006. Two of the suppliers who were named as defendants in those matters, Reliant Energy Services, Inc. (and other Reliant entities) and Duke Energy and Trading, LLP (and other Duke entities), filed cross-claims against various other participants in the PX and California independent system operator markets, including APS, attempting to

expand those matters to such other participants. APS has not yet filed a responsive pleading in the matter, but APS believes the claims by Reliant and Duke as they relate to APS are without merit.

APS was also named in a lawsuit regarding wholesale contracts in California, which has now been moved back to state court. James Millar, et al. v. Allegheny Energy Supply, et al., San Francisco Superior Court, Case No. 407867. The First Amended Complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market, in violation of California unfair competition laws. The PX has filed a lawsuit against the State of California regarding the seizure of forward contracts and the State has filed a cross complaint against APS and numerous other PX participants. Cal PX v. The State of California, Superior Court in and for the County of Sacramento, JCCP No. 4203. Various motions continue to be filed, and we currently believe these claims will have no material adverse impact on our financial position, results of operations or liquidity.

#### **Citizens Power Service Agreement**

By letter dated March 7, 2001, Citizens, which owns a utility in Arizona, advised APS that it believes APS overcharged Citizens by over \$50 million under a power service agreement. APS believes its charges under the agreement were fully in accordance with the terms of the agreement. In addition, in testimony filed with the ACC on March 13, 2002, Citizens acknowledged, based on its review, “if Citizens filed a complaint with the FERC, it probably would lose the central issue in the contract interpretation dispute.” APS and Citizens terminated the power service agreement effective July 15, 2001. In replacement of the power service agreement, the Company and Citizens entered into a power sale agreement under which the Company will supply Citizens with future specified amounts of electricity and ancillary services through May 31, 2008. This new agreement does not address issues previously raised by Citizens with respect to charges under the original power service agreement through June 1, 2001.

#### **Construction Program**

Consolidated capital expenditures in 2004 are estimated to be (dollars in millions):

APS	\$	426
Pinnacle West Energy		61
SunCor		83
Other (primarily APS Energy Services and Pinnacle West)		11
Total	\$	581

### Natural Gas Supply

APS and Pinnacle West Energy purchase the majority of their natural gas requirements for their gas-fired plants under contracts with a number of natural gas suppliers. Effective September 1, 2003, APS' and Pinnacle West Energy's natural gas supply is transported pursuant to a firm, contract demand service agreement with El Paso Natural Gas Company. Pursuant to the terms of a comprehensive settlement entered into in 1996, the rates charged for transportation are subject to a 10-year rate moratorium extending through December 31, 2005.

Prior to September 1, 2003, APS' and Pinnacle West Energy's natural gas supply was transported pursuant to a firm, full requirements transportation service agreement. On July 9, 2003, the FERC issued an order that altered the contractual obligations and the rights of parties to the 1996 settlement by requiring all firm, full requirements contract holders to convert to contract demand service agreements effective September 1, 2003. This required conversion has imposed additional limitations on the former full requirements contract holders' ability to nominate firm transportation capacity. In order for APS and Pinnacle West Energy to meet their natural gas supply and capacity requirements, they must make market purchases, which we expect to increase costs by approximately \$5 million per year for natural gas supply and by approximately \$14 million per year for capacity. APS and Pinnacle West Energy have sought appellate review of the FERC's July 9 order and related issues on the grounds that the FERC decision to abrogate the full requirements contracts is arbitrary and capricious and is not supported by substantial evidence. [Arizona Public Service Company and Pinnacle West Energy Corporation v. Federal Energy Regulatory Commission](#), United States Court of Appeals for the District of Columbia Circuit, No. 03-1209. This petition for review was consolidated with a petition filed by the ACC and other full requirements contract holders. [Arizona Corporation Commission et al v. Federal Energy Regulatory Commission](#), United States Court of Appeals for the District of Columbia Circuit, No. 03-1206. We are continuing to analyze the market to determine the most favorable source and method of meeting our natural gas requirements.

### 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 consolidated financial statements, results of operations or liquidity.

## 12. ASSET RETIREMENT OBLIGATIONS

On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. The standard requires that these liabilities be recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. 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. Prior to January 1, 2003, we accrued asset retirement obligations over the life of the related asset through depreciation expense.

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

On January 1, 2003 and in accordance with SFAS No. 143, APS recorded a liability of \$219 million for its asset retirement obligations, including the accretion impacts; a \$67 million increase in the carrying amount of the associated assets; and a net reduction of \$192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, APS recorded a net regulatory liability of \$40 million for the asset retirement obligations related to its regulated assets. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. APS believes it can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 143. The adoption of SFAS No. 143 did not have a material impact on our net income for the year ended December 31, 2003.

APS has reclassified prior year removal costs of approximately \$557 million previously included in accumulated depreciation to the liability for asset retirements and removals on our Consolidated Balance Sheets. In 2003, APS reclassified the portion of this liability for which no legal obligation for removal exists to a regulatory liability.

In accordance with SFAS No. 71, APS will continue to accrue for removal costs for its regulated assets, even if there is no legal obligation for removal. At December 31, 2003, regulatory liabilities shown on our Consolidated Balance Sheets included approximately \$480 million of estimated future removal costs that are not considered legal obligations.

The following schedule shows the change in our asset retirement obligations during the twelve-month period ended December 31, 2003 (dollars in millions):

Balance at January 1, 2003	\$	219
Changes attributable to:		
Liabilities incurred		–
Liabilities settled		–
Accretion expense		15
Estimated cash flow revisions		–
Balance at December 31, 2003	\$	234

The following schedule shows the change in our pro forma liability for the years ended December 31, 2002 and 2001, as if we had recorded an asset retirement obligation based on the guidance in SFAS No. 143 (dollars in millions):

Years Ended December 31,	2002	2001
Balance at beginning of year	\$ 204	\$ 190
Accretion expense	15	14
Balance at end of year	\$ 219	\$ 204

The pro forma effects on net income for 2002 and 2001 are immaterial.

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. APS invests the trust funds in fixed income and domestic equity securities and classifies them as available for sale.

The following table shows the cost and fair value of APS' nuclear decommissioning trust fund assets which are on the Consolidated Balance Sheets at December 31, 2003 and December 31, 2002 (dollars in millions):

December 31,	2003	2002
Trust fund assets – at cost:		
Fixed income securities	\$ 124	\$ 113
Domestic stock	74	68
Total	\$ 198	\$ 181
Trust fund assets – at fair value:		
Fixed income securities	\$ 140	\$ 117
Domestic stock	101	77
Total	\$ 241	\$ 194

### 13. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Consolidated quarterly financial information for 2003 and 2002 is as follows (dollars in thousands, except per share amounts):

	Operating Revenues as Previously Disclosed (a)	Reclassification Adjustment (b)	Operating Revenues	Operating Income	Income from Continuing Operations	Net Income (d)
2003 quarter ended:						
March 31	\$ 603,962	\$ 51,319	\$ 552,643	\$ 69,255	\$ 20,153	\$ 25,298
June 30	757,483	74,181	683,302	132,482	54,889	56,142
September 30	946,570	98,867	847,703	198,850	109,538	110,048
December 31	734,204	—	734,204	81,466	45,996	49,091
<b>Total</b>		<b>\$ 224,367</b>	<b>\$ 2,817,852</b>	<b>\$ 482,053</b>	<b>\$ 230,576</b>	<b>\$ 240,579</b>

	Operating Revenues as Previously Disclosed (a)	Reclassification Adjustment (b)(c)	Operating Revenues	Operating Income	Income (Loss) from Continuing Operations	Net Income (Loss) (d)
2002 quarter ended:						
March 31	\$ 499,844	\$ 16,365	\$ 483,479	\$ 118,736	\$ 53,251	\$ 53,757
June 30	593,516	18,962	574,554	155,832	68,803	75,365
September 30	871,390	103,450	767,940	212,491	100,713	100,916
December 31 (f)	644,436	30,121	614,315	13,875	(16,569)	(80,630)
<b>Total</b>		<b>\$ 168,898</b>	<b>\$ 2,440,288</b>	<b>\$ 500,934</b>	<b>\$ 206,198</b>	<b>\$ 149,408</b>

(a) Operating revenues previously disclosed in the March 31, 2003, June 30, 2003 and September 30, 2003 Quarterly Reports on Form 10-Q, except for the fourth quarter ended December 31, 2003, which was disclosed in a Pinnacle West Form 8-K dated January 29, 2004 and the fourth quarter ended December 31, 2002, which was disclosed in a Pinnacle West Form 8-K dated February 4, 2003.

(b) Reclassification adjustment of \$224 million in 2003 and \$162 million in 2002 related to the adoption of EITF 03-11 (see Note 18).

(c) Reclassification adjustment of \$7 million in the fourth quarter of 2002 related to discontinued operations at SunCor (see Note 22).

(d) Includes income from discontinued operations at SunCor (see Note 22).

(e) Includes a \$66 million after-tax charge for the cumulative effect of a change in accounting for trading activities (see Note 18).

(f) The fourth quarter of 2002 included pretax losses of \$38 million related to our investment in NAC, a \$49 million pretax write-off related to the cancellation of Redhawk Units 3 and 4 and pretax severance costs of approximately \$11 million.

#### Income From Continuing Operations – EPS:

	2003		2002	
	Basic	Diluted	Basic	Diluted
Quarter ended:				
March 31	\$ 0.22	\$ 0.22	\$ 0.63	\$ 0.63
June 30	0.60	0.60	0.81	0.81
September 30	1.20	1.20	1.19	1.19
December 31	0.50	0.50	(0.19)	(0.19)

#### Net Income – EPS:

	2003		2002	
	Basic	Diluted	Basic	Diluted
Quarter ended:				
March 31	\$ 0.28	\$ 0.28	\$ 0.63	\$ 0.63
June 30	0.62	0.61	0.89	0.89
September 30	1.21	1.20	0.19	1.19
December 31	0.54	0.54	(0.95)	(0.95)

### 14. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents are reasonable estimates of their fair values at December 31, 2003 and 2002 due to their short maturities.

We hold investments in fixed income and domestic equity securities for purposes other than trading. The December 31, 2003 and 2002 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, 2003, the carrying value of our long-term debt (excluding capitalized lease obligations) was \$3.32 billion, with an estimated fair value of \$3.46 billion. The carrying value of our long-term debt (excluding capitalized lease obligations) was \$3.00 billion on December 31, 2002, with an estimated fair value of \$3.21 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, 2003, 2002 and 2001:

	2003	2002	2001
Basic earnings per share:			
Income from continuing operations	\$ 2.53	\$ 2.43	\$ 3.86
Income from discontinued operations	0.11	0.10	–
Cumulative effect of change in accounting	–	(0.77)	(0.18)
Earnings per share – basic	\$ 2.64	\$ 1.76	\$ 3.68
Diluted earnings per share:			
Income from continuing operations	\$ 2.52	\$ 2.43	\$ 3.85
Income from discontinued operations	0.11	0.10	–
Cumulative effect of change in accounting	–	(0.77)	(0.17)
Earnings per share – diluted	\$ 2.63	\$ 1.76	\$ 3.68

Dilutive stock options increased average common shares outstanding by approximately 140,000 shares in 2003, 61,000 shares in 2002 and 212,000 shares in 2001. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 91,405,134 shares in 2003, 84,963,921 shares in 2002 and 84,930,140 shares in 2001.

Options to purchase 2,291,646 shares of common stock were outstanding at December 31, 2003 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 1,629,958 at December 31, 2002 and 212,562 at December 31, 2001.

## 16. STOCK-BASED COMPENSATION

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

In May 2002, shareholders approved the 2002 Long-Term Incentive Plan (2002 plan), which allows Pinnacle West to grant performance shares, stock ownership incentive awards and non-qualified and performance-accelerated stock options to key employees. The Company has reserved 6 million shares of common stock for issuance under the 2002 plan. No more than 1.8 million shares may be issued in relation to performance share awards and stock ownership incentive awards. The plan also provides for the granting of new non-qualified stock options at a price per share not less than the fair market value of the common stock at the time of grant.

The stock options vest over three years, unless certain performance criteria are met, which can accelerate the vesting period. The term of the option cannot be longer than 10 years and the option cannot be repriced during its term.

The 1994 plan and the 1985 plan each include outstanding options but no new options will be granted under either plan. Options vest 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. Following the approval of the 2002 plan, no further grants have been made under the 1994 plan, except for awards for the annual award of up to 20,000 shares of stock to satisfy stock award obligations under employment contracts to certain executives.

In the third quarter of 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123. The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in APB No. 25. We recorded approximately \$2.1 million in stock option expense before income taxes in our Consolidated Statements of Income in 2003 and approximately \$0.5 million in 2002. This amount may not be reflective of the stock option expense we will record in future years because stock options typically vest over several years and additional grants are generally made each year.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The standard amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based compensation. The standard also amends the disclosure requirements of SFAS No. 123. SFAS No. 148 is effective for fiscal years ending after December 15, 2002. We adopted the disclosure requirements in 2002. See Note 1 for our pro forma disclosures on stock-based compensation and our weighted-average assumptions used to calculate the fair value of our stock options.

Total stock-based compensation cost, including stock option cost, was \$6 million in 2003, \$5 million in 2002 and \$3 million in 2001.

The following table is a summary of the status of our stock option plans as of December 31, 2003, 2002 and 2001 and changes during the years ending on those dates:

	2003 Weighted		2002 Weighted		2001 Weighted	
	2003 Shares	Average Exercise Price	2002 Shares	Average Exercise Price	2001 Shares	Average Exercise Price
Outstanding at beginning of year	2,185,129	\$ 39.96	1,832,725	\$ 39.52	1,569,171	\$ 37.55
Granted	621,875	32.29	603,900	38.37	444,200	42.55
Exercised	(62,366)	26.09	(163,381)	28.25	(162,229)	28.53
Forfeited	(46,392)	37.61	(88,115)	41.54	(18,417)	41.67
Outstanding at end of year	<u>2,698,246</u>	38.56	<u>2,185,129</u>	39.96	<u>1,832,725</u>	39.52
Options exercisable at year-end	<u>1,787,622</u>	40.35	<u>1,155,357</u>	39.66	<u>926,315</u>	37.41
Weighted average fair value of options granted during the year		\$ 7.37		\$ 6.16		\$ 8.84

The following table summarizes information about our stock options at December 31, 2003:

Exercise Prices Per Share	Options Outstanding	Weighted-Average Exercise Price	Weighted Average Remaining Contract Life (Years)	Options Exercisable	Weighted-Average Exercise Price
23.39-28.07	48,417	27.40	2.3	48,417	27.40
28.07-32.75	647,400	32.23	8.7	49,625	31.50
32.75-37.42	220,994	34.70	5.4	220,994	34.70
37.42-42.10	759,333	38.86	6.7	579,854	38.95
42.10-46.78	<u>1,011,518</u>	43.96	6.1	<u>878,148</u>	44.17
	<u>2,698,246</u>			<u>1,787,622</u>	

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, 2003, 2002 and 2001:

	2003		2002		2001	
	Shares	Grant Price	Shares	Grant Price	Shares	Grant Price
Restricted stock	4,000	\$ 32.20(a)	6,000	\$ 38.84(a)	95,450	\$ 42.84(a)
Performance share awards	119,085	32.29(b)	115,975	38.37(b)	-	-

(a) Restricted stock priced at the average of the high and low market price for the grant date.

(b) Performance shares priced at the closing market price for 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 and related activities, and includes electricity generation, transmission and distribution;
- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading and APS Energy Services' commodity-related energy services. In early 2003, we moved our marketing and trading

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

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

The amounts in our other segment include activity principally related to El Dorado's investment in NAC, as well as the parent company and other subsidiaries. See Note 18 for information about reclassifications related to the adoption of EITF 03-11. Financial data for the years ended December 31, 2003, 2002 and 2001 by business segments is provided as follows (dollars in millions):

**Business Segments for the Year Ended December 31, 2003**

	Regulated Electricity	Marketing and Trading	Real Estate	Other (principally NAC)	Total
Operating revenues	\$ 1,978	\$ 392	\$ 362	\$ 86	\$ 2,818
Purchased power and fuel costs	517	345	-	-	862
Other operating expenses	625	34	306	71	1,036
Operating margin	836	13	56	15	920
Depreciation and amortization	428	1	6	3	438
Interest expense	172	-	2	1	175
Other expense/(income)	(4)	-	(25)	-	(29)
Pretax margin	240	12	73	11	336
Income taxes	70	3	28	4	105
Income from continuing operations	170	9	45	7	231
Income from discontinued operations – net of income taxes of \$6 (see Note 22)	-	-	10	-	10
Net income	\$ 170	\$ 9	\$ 55	\$ 7	\$ 241
Total assets	\$ 8,761	\$ 324	\$ 424	\$ 27	\$ 9,536
Capital expenditures	\$ 686	\$ 9	\$ 72	\$ -	\$ 767

**Business Segments for the Year Ended December 31, 2002**

	Regulated Electricity	Marketing and Trading	Real Estate	Other (principally NAC)	Total
Operating revenues	\$ 1,890	\$ 287	\$ 201	\$ 62	\$ 2,440
Purchased power and fuel costs	377	155	-	-	532
Other operating expenses	659	34	185	105	983
Operating margin	854	98	16	(43)	925
Depreciation and amortization	416	2	4	2	424
Interest expense	141	-	2	1	144
Other expense/(income)	19	-	(7)	7	19
Pretax margin	278	96	17	(53)	338
Income taxes	108	38	7	(21)	132
Income (loss) from continuing operations	170	58	10	(32)	206
Income from discontinued operations – net of income taxes of \$6 (see Note 22)	-	-	9	-	9
Cumulative effect of change in accounting for trading activities – net of income taxes of \$43	-	(66)	-	-	(66)
Net income (loss)	\$ 170	\$ (8)	\$ 19	\$ (32)	\$ 149
Total assets	\$ 8,185	\$ 414	\$ 504	\$ 36	\$ 9,139
Capital expenditures	\$ 893	\$ 19	\$ 72	\$ -	\$ 984

## Business Segments for the Year Ended December 31, 2001

	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	\$ 1,984	\$ 470	\$ 169	\$ 12	\$ 2,635
Purchased power and fuel costs	583	153	–	–	736
Other operating expenses	598	33	154	11	796
Operating margin	803	284	15	1	1,103
Depreciation and amortization	423	1	4	–	428
Interest expense	125	–	3	–	128
Other expense/(income)	4	–	3	–	7
Pretax margin	251	283	5	1	540
Income taxes	99	112	2	–	213
Income before accounting change	152	171	3	1	327
Cumulative effect of change in accounting for derivatives – net of income taxes of \$10	(15)	–	–	–	(15)
Net income	\$ 137	\$ 171	\$ 3	\$ 1	\$ 312
Capital expenditures	\$ 1,004	\$ 23	\$ 80	\$ 22	\$ 1,129

**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 and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. 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. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERM, we engage in marketing and trading activities intended to profit from market price movements.

Effective January 1, 2001, we adopted SFAS No. 133. 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 hedge criteria is met, in common stock equity (as a component of other comprehensive income (loss)). We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. 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.

In 2001, we recorded a \$15 million after-tax charge in net income and a \$72 million after-tax credit in common stock equity (as a component of other comprehensive income (loss)), both as cumulative effects of a change in accounting for derivatives.

The charge primarily resulted from electricity option contracts. The credit resulted from unrealized gains on cash flow hedges.

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts, and on January 1, 2003 for existing contracts, with early adoption permitted. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. We recorded a \$66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Energy 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. Additionally, 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. Derivative instruments used for non-trading activities are accounted for in accordance with SFAS No. 133.

Both non-trading and trading derivatives are classified as assets and liabilities from risk management and trading activities in the Consolidated Balance Sheets. For non-trading derivative instruments that qualify for cash flow hedge accounting treatment, changes in the fair value of the effective portion are recognized in common stock equity (as a component of other comprehensive income (loss)). Non-trading derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. Gains and losses related to non-trading derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If it becomes probable that a forecasted transaction will not occur, we discontinue the use of hedge accounting and recognize in income the unrealized gains and losses

that were previously recorded in other comprehensive income (loss). In the event a non-trading derivative is terminated or settled, the unrealized gains and losses remain in other comprehensive income (loss), and are recognized in income when the underlying transaction impacts earnings. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception and are not reflected on the balance sheet at fair value. Certain of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered. Derivatives associated with trading activities are adjusted to fair value through income.

EITF 02-3 requires that derivatives held for trading purposes, whether settled financially or physically, be reported in the income statement on a net basis. Previous guidance under EITF 98-10 permitted physically-settled energy trading contracts to be reported either gross or net in the income statement. Beginning in the third quarter of 2002, we netted all of our energy trading activities on the Consolidated Statements of Income and restated prior year amounts for all periods presented. Reclassification of such trading activity to a net basis of reporting resulted in reductions in both revenues and purchased power and fuel costs, but did not have any impact on our financial condition, net income or cash flows.

We adopted EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in Issue No. 02-3," effective October 1, 2003. EITF 03-11 provided guidance on whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported on a net or gross basis and concluded such classification is a matter of judgment that depends on the relevant facts and circumstances. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called "book-out" and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We netted these book-outs reducing both revenues and purchased power and fuel costs in 2003, 2002 and 2001, but this did not impact our financial condition, net income or cash flows. Following are the net reclassifications to our previously reported amounts (dollars in thousands):

Year Ended December 31,	2003	2002	2001
Regulated Electricity	\$ 40,069	\$ 122,632	\$ 577,783
Marketing and Trading	184,298	39,052	181,447
Total	\$ 224,367	\$ 161,684	\$ 759,230

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

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." This statement amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under SFAS No. 133. The provisions of SFAS No. 149 that relate to previously issued SFAS No. 133 derivatives implementation guidance should continue to be applied in accordance with the effective dates of the original implementation guidance. In general, other provisions are applied prospectively to contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The impact of this standard was immaterial to our financial statements.

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

Year Ended December 31,	2003	2002
Gains on the ineffective portion of derivatives qualifying for hedge accounting	\$ 8,237	\$ 13,682
Gains/(losses) from the change in options' time value excluded from measurement of effectiveness	181	(2,484)
Losses from the discontinuance of cash flow hedges	-	(8,820)

As of December 31, 2003, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions is approximately five years. During the year ending December 31, 2004, we estimate that a net gain of \$8 million before income taxes will be reclassified from accumulated other comprehensive loss as an offset to the effect on earnings of market price changes for the related hedged transactions.

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

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

The following table summarizes our assets and liabilities from risk management and trading activities at December 31, 2003 and 2002 (dollars in thousands):

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

December 31, 2002	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated Electricity:					
Mark-to-Market	\$ 41,522	\$ 6,971	\$ (60,819)	\$ (36,678)	\$ (49,004)
Options	–	24,651	–	–	24,651
Marketing and Trading:					
Mark-to-Market	61,142	121,189	(50,510)	(74,841)	56,980
Emission allowances – at cost	–	38,943	–	(36,381)	2,562
<b>Total</b>	<b>\$ 102,664</b>	<b>\$ 191,754</b>	<b>\$ (111,329)</b>	<b>\$ (147,900)</b>	<b>\$ 35,189</b>

Cash or collateral may be required to serve as collateral against our open positions on certain energy-related contracts. Collateral provided to counterparties is \$1 million at December 31, 2003 and \$5 million at December 31, 2002, and is included in investments and other assets on the Consolidated Balance Sheet. Collateral provided to us by counterparties is \$12 million at December 31, 2003 and \$22 million at December 31, 2002, and is included in other deferred credits on the Consolidated Balance Sheet.

#### Credit Risk

We are exposed to losses in the event of nonperformance or non-payment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 37% of our \$237 million of risk management and trading assets as of December 31, 2003. Our risk management process assesses and monitors the financial exposure of these and all other counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, including the counterparties noted above, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition.

In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See Note 1 "Mark-to-Market Accounting" for a discussion of our credit valuation adjustment policy.

#### 19. OTHER INCOME AND OTHER EXPENSE

The following table provides detail of other income and other expense for the years ended December 31, 2003, 2002 and 2001 (dollars in thousands):

Year Ended December 31,	2003	2002	2001
Other income:			
SunCor joint venture earnings (a)	\$ 24,740	\$ 7,355	\$ 3,687
Interest income	4,412	4,332	6,763
Investment gains	3,649	–	–
Environmental insurance recovery	–	–	12,349
Miscellaneous	2,762	3,223	3,617
<b>Total other income</b>	<b>\$ 35,563</b>	<b>\$ 14,910</b>	<b>\$ 26,416</b>
Other expense:			
Non-operating costs (b)	\$ (16,481)	\$ (19,430)	\$ (16,807)
Investment losses (c)	–	(10,439)	(5,126)
Non-operating costs – SunCor	–	–	(7,000)
Miscellaneous	(4,093)	(3,786)	(4,644)
<b>Total other expense</b>	<b>\$ (20,574)</b>	<b>\$ (33,655)</b>	<b>\$ (33,577)</b>

(a) Primarily related to the sale at SunCor of a land interest and profit participation agreement in the fourth quarter of 2003 for \$18 million. In 2002, SunCor received \$2.5 million for the profit participation.

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

(c) Primarily related to El Dorado's investment losses in NAC prior to consolidation in the third quarter of 2002.

## 20. VARIABLE INTEREST ENTITIES

In 2003, we adopted FIN No. 46R, "Consolidation of Variable Interest Entities," as it applies to special-purpose entities. FIN No. 46R requires that we consolidate a VIE if we have a majority of the risk of loss from the VIE's activities or we are entitled to receive a majority of the VIE's residual returns or both. A VIE is a corporation, partnership, trust or any other legal structure that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities. In 1986, APS entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 9 for further information about the sale leaseback transactions. Based on our assessment of FIN No. 46R, we are not required to consolidate the Palo Verde VIEs. Certain provisions of FIN No. 46R have a future effective date. We do not expect these provisions to have a material impact on our financial statements.

APS is exposed to losses under the Palo Verde sale leaseback agreements upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2003, APS would have been required to assume approximately \$268 million of debt and pay the equity participants approximately \$200 million.

## 21. GUARANTEES

On January 1, 2003, we adopted FIN No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN No. 45 elaborates on the disclosures to be made by a guarantor in its financial statements about its obligations under certain guarantees. It also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The disclosure provisions were effective for the year ended December 31, 2002. The initial recognition and measurement provisions of FIN No. 45 were effective on a prospective basis to guarantees issued or modified after December 31, 2002.

We have issued parental guarantees and letters of credit and obtained surety bonds on behalf of our unregulated subsidiaries. Our parental guarantees related to Pinnacle West Energy consist

of equipment and performance guarantees related to our generation construction program, transmission service guarantees for West Phoenix Units 4 and 5 and long-term service agreement guarantees for new power plants. Our credit support instruments enable APS Energy Services to offer commodity energy and energy-related products and enable El Dorado to support the activities of NAC. Non-performance or payment under the original contract by our unregulated subsidiaries would require us to perform under the guarantee or surety bond. No liability is currently recorded on the Consolidated Balance Sheets related to Pinnacle West's guarantees on behalf of its subsidiaries. Our guarantees have no recourse (except NAC) or collateral provisions to allow us to recover amounts paid under the guarantee. The amounts and approximate terms of our guarantees and surety bonds for each subsidiary at December 31, 2003 are as follows (dollars in millions):

	Guarantees		Surety Bonds	
	Amount	Term (in years)	Amount	Term (in years)
Parental:				
Pinnacle West Energy	\$ 86	1 to 2	\$ -	-
APS Energy Services	16	1 to 2	35	2
El Dorado (NAC)	40	1 to 3	-	-
Total	<u>\$ 142</u>		<u>\$ 35</u>	

At December 31, 2003, we had entered into approximately \$41 million of letters of credit which support various construction agreements. These letters of credit expire in 2004 and 2005. We intend to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required. At December 31, 2003, Pinnacle West has approximately \$4 million of letters of credit related to workers' compensation expiring in 2004.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2003, 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. These letters of credit have expiration dates in 2004 and 2005. APS has also entered into approximately \$109 million of letters of credit to support certain equity lessors in the Palo Verde sale leaseback transactions (see Note 9 for further details on the Palo Verde sale leaseback transactions). These letters of credit expire in 2005. Additionally, APS has approximately \$5 million of letters of credit related to counterparty collateral requirements expiring in 2004. APS intends to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required.

We provide indemnifications relating to liabilities arising from or related to certain of our agreements. APS has provided indemnifications to the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnifications is likely and therefore no related liability has been recorded.

## 22. REAL ESTATE ACTIVITIES – DISCONTINUED OPERATIONS

Certain components of SunCor's real estate sales activities, which are included in the real estate segment, are required to be reported as discontinued operations on our Consolidated Statements of Income in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Among other guidance, SFAS No. 144 prescribes accounting for discontinued operations and defines certain activities as discontinued operations. We adopted SFAS No. 144 effective January 1, 2002 and determined that activities that would have required discontinued operations reporting in 2002 and 2001 were immaterial.

In 2003, SunCor sold its water utility company, which resulted in an after-tax gain of \$8 million (\$14 million pretax). The amounts of the gain on the sale and operating income of the water utility company in 2003 and 2002 are classified as discontinued operations on our Consolidated Statements of Income. The amounts related to 2001 were immaterial for reclassification.

In the second quarter of 2002, SunCor sold a retail center, but maintained a continuing involvement through a management contract. In the first quarter of 2003, this management contract was canceled. As a result, the after-tax gain of \$6 million (\$10 million pre-tax) recorded in operations in 2002 related to this property was reclassified as discontinued operations on our Consolidated Statements of Income. The income from discontinued operations in the year ended December 31, 2002 primarily reflects this sale. The amounts related to 2001 were immaterial for reclassification.

In the fourth quarter of 2003, SunCor sold a retail center, which resulted in an after-tax gain of \$2 million (\$3 million pretax). The gain on the sale and the operating income related to this property in 2003 are classified as discontinued operations on our Consolidated Statements of Income. There were no prior-year operations related to this retail center. The amounts related to 2001 were immaterial for reclassification.

The following table provides SunCor's revenue and income before income taxes related to properties classified as discontinued operations on our consolidated statements of income for the years ended December 31, 2003 and 2002 (dollars in thousands):

	2003	2002
Revenue	\$ 70,580	\$ 35,307
Income before taxes	\$ 16,532	\$ 14,827

The following tables provide the amounts related to properties of discontinued operations which were reclassified to assets and liabilities held for sale on the Consolidated Balance Sheets at December 31, 2003 and 2002 (dollars in thousands):

	2003	2002
Real estate investments – net	\$ –	\$ 39,849
Other	–	2,490
Real estate assets held for sale	\$ –	\$ 42,339

	2003	2002
Customer deposits	\$ –	\$ 13,648
Long-term debt less current maturities	–	12,454
Other	–	2,753
Real estate liabilities held for sale	\$ –	\$ 28,855

See Note 17 for information related to the real estate segment.