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GLOSSARY

ACC - Arizona Corporation Commission
ALJ - Administrative Law Judge
CC&N - Certificate of Convenience and Necessity
CHOLLA - Cholla Power Plant
CITIZENS - Citizens Communications Company
EITF - Emerging Issues Task Force
FERC - United States Federal Energy Regulatory Commission
FOUR CORNERS - Four Corners Power Plant
ISO - California Independent System Operator
ITC - Investment tax credit
1999 SETTLEMENT AGREEMENT - Settlement among APS and other parties related to the implementation of retail electric competition in Arizona
NRC - United States Nuclear Regulatory Commission
PALO VERDE - Palo Verde Nuclear Generating Station
PPA - Purchase Power Agreement
PX - California Power Exchange
RULES - ACC retail electric competition rules
SALT RIVER PROJECT - Salt River Project Agricultural Improvement and Power District

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

year ended December 31,	2001	2000	1999	1998	1997
OPERATING RESULTS					
Operating revenues					
Electric	**$ 4,382,465**	$ 3,531,810	$ 2,293,184	$ 2,006,398	$ 1,878,553
Real estate	**168,908**	158,365	130,169	124,188	116,473
Income from continuing operations	**$ 327,367**	$ 302,332	$ 269,772	$ 242,892	$ 235,856
Discontinued operations (a)	**–**	–	38,000	–	–
Extraordinary charge – net of income taxes (b)	**–**	–	(139,885)	–	–
Cumulative effect of change in accounting – net of income taxes (c)	**(15,201)**	–	–	–	–
Net income	**$ 312,166**	$ 302,332	$ 167,887	$ 242,892	$ 235,856
COMMON STOCK DATA					
Book value per share – year-end	**$ 29.46**	$ 28.09	$ 26.00	$ 25.50	$ 23.90
Earnings (loss) per weighted average common share outstanding					
Continuing operations – basic	**$ 3.86**	$ 3.57	$ 3.18	$ 2.87	$ 2.76
Discontinued operations	**–**	–	0.45	–	–
Extraordinary charge	**–**	–	(1.65)	–	–
Cumulative effect of change in accounting	**(0.18)**	–	–	–	–
Net income – basic	**$ 3.68**	$ 3.57	$ 1.98	$ 2.87	$ 2.76
Continuing operations – diluted	**$ 3.85**	$ 3.56	$ 3.17	$ 2.85	$ 2.74
Net income – diluted	**$ 3.68**	$ 3.56	$ 1.97	$ 2.85	$ 2.74
Dividends declared per share	**$ 1.525**	$ 1.425	$ 1.325	$ 1.225	$ 1.125
Indicated annual dividend rate per share – year-end	**$ 1.60**	$ 1.50	$ 1.40	$ 1.30	$ 1.20
Weighted-average common shares outstanding – basic	**84,717,649**	84,732,544	84,717,135	84,774,218	85,502,909
Weighted-average common shares outstanding – diluted	**84,930,140**	84,935,282	85,008,527	85,345,946	86,022,709
BALANCE SHEET DATA					
Total assets	**$ 7,981,748**	$ 7,162,985	$ 6,608,506	$ 6,824,546	$ 6,850,417
Liabilities and equity:					
Long-term debt less current maturities	**$ 2,673,078**	$ 1,955,083	$ 2,206,052	$ 2,048,961	$ 2,244,248
Other liabilities	**2,809,347**	2,825,188	2,196,721	2,516,993	2,407,572
Total liabilities	**5,482,425**	4,780,271	4,402,773	4,565,954	4,651,820
Minority interests					
Non-redeemable preferred stock of APS	**–**	–	–	85,840	142,051
Redeemable preferred stock of APS	**–**	–	–	9,401	29,110
Common stock equity	**2,499,323**	2,382,714	2,205,733	2,163,351	2,027,436
Total liabilities and equity	**$ 7,981,748**	$ 7,162,985	$ 6,608,506	$ 6,824,546	$ 6,850,417

(a) Tax benefit stemming from the resolution of income tax matters related to a former subsidiary MeraBank, A Federal Savings Bank. See Note 4.
(b) Charges associated with a regulatory disallowance. See Note 3.
(c) Change in accounting standards related to derivatives. See Note 17.

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

year ended December 31,	2001	2000	1999	1998	1997
ELECTRIC OPERATING REVENUES					
Retail					
Residential	**$ 914,711**	$ 880,468	$ 805,173	$ 766,378	$ 746,937
Business	**952,627**	935,214	911,449	889,244	873,232
Total retail	**1,867,338**	1,815,682	1,716,622	1,655,622	1,620,169
Wholesale revenue on delivered electricity:					
Traditional contracts	**73,305**	120,618	60,486	58,184	63,027
Retail load hedge management	**577,784**	560,493	108,153	–	–
Marketing and trading – delivered:					
Generation other than native load (a)	**148,316**	115,476	29,551	–	–
Other delivered electricity (a)	**1,560,185**	874,619	345,067	258,058	163,801
Total delivered marketing and trading	**1,708,501**	990,095	374,618	258,058	163,801
Total delivered wholesale electricity	**2,359,590**	1,671,206	543,257	316,242	226,828
Other marketing and trading:					
Realized margins on delivered commodities other than electricity	**(13,646)**	(8,789)	2,483	7,192	3,618
Prior period mark-to-market (gains) losses on contracts delivered during current period	**(1,059)**	(2,079)	–	–	–
Change in mark-to-market for future period deliveries	**126,580**	13,831	975	–	–
Total other marketing and trading	**111,875**	2,963	3,458	7,192	3,618
Transmission for others	**25,971**	14,765	11,348	11,058	10,295
Other miscellaneous services	**17,691**	27,194	18,499	16,284	17,643
Total electric operating revenues	**$ 4,382,465**	$ 3,531,810	$ 2,293,184	$ 2,006,398	$ 1,878,553

(a) The break-out of generation other than native load is not available for 1997 through 1998.

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

year ended December 31,	2001	2000	1999	1998	1997
ELECTRIC SALES (MWh)					
Retail:					
Residential	**10,334,860**	9,780,680	8,774,822	8,310,689	7,970,309
Business	**13,064,152**	12,753,844	12,299,748	12,152,394	11,846,618
Total retail	**23,399,012**	22,534,524	21,074,570	20,463,083	19,816,927
Wholesale electricity delivered:					
Traditional contracts	**1,213,704**	1,610,032	1,421,522	1,410,392	1,486,439
Retail load hedge management	**3,039,905**	6,673,658	630,945	–	–
Marketing and trading – delivered:					
Generation other than native load (a)	**1,387,860**	1,494,299	1,267,349	–	–
Other delivered electricity (a)	**14,612,997**	12,219,368	12,374,018	8,906,999	7,747,134
Total delivered marketing and trading	**16,000,857**	13,713,667	13,641,367	8,906,999	7,747,134
Total delivered wholesale electricity	**20,254,466**	21,997,357	15,693,834	10,317,391	9,233,573
Total electric sales	**43,653,478**	44,531,881	36,768,404	30,780,474	29,050,500
ELECTRIC CUSTOMERS – AVERAGE					
Retail:					
Residential	**776,339**	749,285	719,774	689,871	663,493
Business	**98,198**	94,128	90,496	87,831	84,576
Total retail	**874,537**	843,413	810,270	777,702	748,069
Wholesale	**66**	67	69	60	59
Total customers	**874,603**	843,480	810,339	777,762	748,128

(a) The break-out of generation other than native load is not available for 1997 through 1998.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of certain information in the tables above.

QUARTERLY STOCK PRICES AND DIVIDENDS PER SHARE Stock Symbol: PNW

2001	HIGH	LOW	CLOSE	DIVIDENDS PER SHARE	2000	HIGH	LOW	CLOSE	DIVIDENDS PER SHARE
1st Quarter	**$ 47.96**	**$ 39.06**	**$ 45.87**	**$ 0.375**	1st Quarter	$ 32.31	$ 26.25	$ 28.19	$ 0.350
2nd Quarter	**50.70**	**45.20**	**47.40**	**0.375**	2nd Quarter	35.88	27.88	33.88	0.350
3rd Quarter	**49.93**	**37.65**	**39.70**	**0.375**	3rd Quarter	51.31	33.81	50.89	0.350
4th Quarter	**43.50**	**38.00**	**41.85**	**0.400**	4th Quarter	52.22	40.89	47.63	0.375

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

In this section, we explain the results of operations, general financial condition, and outlook for Pinnacle West Capital Corporation and our subsidiaries: Arizona Public Service Company (APS), Pinnacle West Energy Corporation (Pinnacle West Energy), APS Energy Services Company, Inc. (APSES), SunCor Development Company (SunCor), and El Dorado Investment Company (El Dorado) including:

- the changes in our earnings from 2000 to 2001 and from 1999 to 2000;
- our capital needs, liquidity and capital resources;
- our marketing and trading activities;
- our financial outlook;
- our critical accounting policies
- major factors that affect our financial outlook; and
- our management of market risks.

OVERVIEW OF OUR BUSINESS

Pinnacle West owns all of the outstanding common stock of APS. APS is Arizona's largest electric utility and provides either retail or wholesale electric service to substantially all of the state, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates and, through our marketing and trading division, sells and delivers electricity to wholesale customers in the western United States.

Our other major subsidiaries are:

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

Pinnacle West's marketing and trading division sells in the wholesale market APS and Pinnacle West Energy generation production output that is not needed for APS' native load, which includes loads for retail customers and traditional cost-of-service wholesale customers. Subject to specified risk parameters established by our Board of Directors, the marketing and trading division also engages in activities to hedge purchases and sales of electricity, fuels, and emissions allowance and credits and to profit from market price movements. We explain in detail below the historical and prospective contribution of marketing and trading activities to our financial results.

APS is required to transfer its competitive electric assets and services to one or more corporate affiliates no later than December 31, 2002. Consistent with that requirement, APS has been addressing the legal and regulatory requirements necessary to complete the transfer of its generation assets to Pinnacle West Energy before that date. As we discuss in greater detail below under "Business Outlook – Other Factors Affecting Our Financial Outlook," recent Arizona regulatory developments have raised uncertainty about the status and pace of retail electric competition in Arizona, including APS' transfer of generation assets to Pinnacle West Energy.

BUSINESS SEGMENTS

We have two principal business segments (determined by products, services and regulatory environment), which consist of regulated retail electricity business and related activities (retail business segment) and competitive business activities (marketing and trading segment). Our retail business segment currently includes activities related to electricity transmission and distribution, as well as electricity generation. Our marketing and trading segment currently includes activities related to wholesale marketing and trading, and APSES' competitive energy services.

These reportable segments reflect a change in the reporting of our segment information. Before the fourth quarter of 2001, we had two segments (generation and delivery). The "generation segment" information combined our marketing and trading activities with our generation of electricity activities. The "delivery segment" included transmission and distribution activities.

In the fourth quarter, APS filed with the ACC a request for a proposed rule variance and approval of a purchase power agreement (see Note 3) that inherently views our business in the new reportable segments described as presented herein. Internal management reporting has been changed to reflect this alignment. See "Business Segments" in Note 16 for more information about our business segments.

The following is a summary of net income by business segment for 2001, 2000, and 1999:

(dollars in millions)	2001	2000	1999
Retail	$ 152	$ 225	$ 246
Marketing and trading	172	63	5
Other	3	14	19
Income from continuing operations	327	302	270
Income tax benefit from discontinued operations	–	–	38
Extraordinary charge – net of income taxes	–	–	(140)
Cumulative effect of change in accounting – net of income taxes	(15)	–	–
Net Income	$ 312	$ 302	$ 168

Throughout this section, we refer to specific "Notes" in the Notes to Consolidated Financial Statements that begin on page 38. These Notes add further details to the discussion.

RESULTS OF OPERATIONS

The following is a summary of our net income by legal entity for 2001, 2000, and 1999:

(dollars in millions)	2001	2000	1999
APS	$ 281	$ 307	$ 267
Pinnacle West Energy	18	(2)	–
APSES	(10)	(13)	(9)
SunCor	3	11	6
El Dorado	–	2	11
Parent company (a)	35	(3)	(5)
Income from continuing operations	327	302	270
Income tax benefit from discontinued operations	–	–	38
Extraordinary charge – net of income taxes	–	–	(140)
Cumulative effect of change in accounting – net of income taxes	(15)	–	–
Net income	$ 312	$ 302	$ 168

(a) The 2001 amount primarily includes marketing and trading activities. APS also includes some marketing and trading activities. (see Note 16 for further discussion of our business segments.)

2001 Compared With 2000

Our consolidated net income for the year ended December 31, 2001 was $312 million compared with $302 million for the year ended December 31, 2000. In 2001, we recognized a $15 million after-tax loss in net income as a cumulative effect of a change in accounting for derivatives. See Note 17 for further discussion on accounting for derivatives.

Income from continuing operations for the year ended December 31, 2001 was $327 million compared with $302 million for the year ended December 31, 2000. The year-to-year comparison benefited from strong marketing and trading results, including significant benefits in the 2001 third quarter from structured trading activities, and retail customer growth. These factors were partially offset by higher purchased power and fuel costs, due in part to increased power plant maintenance; generation reliability measures; continuing retail electricity price decreases; and a charge related to Enron and its affiliates.

The major factors that increased (decreased) income from continuing operations were as follows:

(dollars in millions)	INCREASE (DECREASE)
Increases (decreases) in electric revenues, net of purchased power and fuel expense due to:	
Marketing and trading activities:	
Increase from generation sales other than native load due to higher market prices	$ 25
Increase in other realized marketing and trading in current period primarily due to more transactions	45
Change in prior year period mark-to-market value for losses transferred to realized margin in current period	16 (a)
Change in prior period mark-to-market value related to trading with Enron and its affiliates	(8)(b)
Increase in mark-to-market value related to future periods	113 (a)
Net increase in marketing and trading	191
Higher replacement power costs for plant outages related to higher market prices	(70)
Retail price reductions (see Note 3)	(27)
Charges related to purchased power contracts with Enron and its affiliates	(13)(b)
Higher retail sales primarily related to customer growth	35
Miscellaneous revenues	3
Total increase in revenues, net of purchased power and fuel expense	119
Decrease in real estate contributions	(8)
Higher operations and maintenance expense related to 2001 generation reliability program	(42)
Higher operations and maintenance expense related primarily to employee benefits, plant outage and maintenance; and other costs	(38)
Lower net interest expense primarily due to higher capitalized interest	17
Higher other net expense	(5)
Miscellaneous items, net	1
Net increase in income from continuing operations before income taxes	44
Higher income taxes primarily due to higher income	(19)
Net increase in income from continuing operations	$ 25

(a) Essentially all of our marketing and trading activities are structured activities. This means our portfolio of forward sales positions is hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.
(b) We recorded charges totaling $21 million before income taxes for exposure to Enron and its affiliates in the fourth quarter of 2001.

Electric operating revenues increased approximately $850 million because of:

- changes in marketing and trading revenues ($827 million, net increase):
  - increased revenues related to generation sales other than native load as a result of higher average market prices ($32 million);
  - increased realized revenues related to other marketing and trading in current period primarily due to more transactions ($681 million);
  - decreased prior period mark-to-market value related to trading with Enron and its affiliates ($8 million);
  - increased prior period mark-to-market value for losses transferred to realized margin in current period ($9 million);
  - increased mark-to-market value for future periods primarily as a result of more forward sales volumes ($113 million);
- decreased revenues related to other wholesale sales and miscellaneous revenues as a result of sales volumes ($28 million);
- increased retail revenues primarily related to higher sales volumes primarily due to customer growth ($78 million); and
- decreased retail revenues related to reductions in retail electricity prices ($27 million).

Purchased power and fuel expenses increased approximately $731 million primarily because of:

- changes in marketing and trading purchased power and fuel costs ($636 million, net increase) due to:
  - increased fuel costs related to generation sales other than native load as a result of higher fuel prices ($7 million);
  - increased fuel and purchased power costs related to other realized marketing and trading in current period primarily due to more transactions ($636 million);
  - decreased mark-to-market fuel costs related to accounting for derivatives ($7 million) (see Note 17)
- decreased costs related to other wholesale sales as a result of lower volumes ($31 million);
- higher replacement power costs primarily due to higher market prices and increased plant outages ($70 million), including costs of $12 million related to a Palo Verde outage extension to replace fuel control element assemblies;
- higher costs related to retail sales volumes due to customer growth ($43 million); and
- charges related to purchased power contracts with Enron and its affiliates ($13 million).

The decrease in real estate profits of $8 million resulted primarily from decreases in sales of land and homes by SunCor.

The increase in operations and maintenance expenses of $80 million primarily related to the 2001 generation summer reliability program (the addition of generating capability to enhance reliability for the summer of 2001 ($42 million)) and increased employee benefit costs, plant outage and maintenance, and other costs ($38 million). The comparison reflects Pinnacle West's $10 million provision 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.

Net other expense increased $5 million primarily because of a change in the market value of El Dorado's investment in a technology-related venture capital partnership in 2000 (see Note 1) and other non-operating costs partially offset by an insurance recovery of environmental remediation costs.

Interest expense decreased by $17 million primarily because of increased capitalized interest resulting from our generation expansion plan partially offset with higher interest expense due to higher debt balances.

2000 Compared With 1999

Our consolidated net income for the year ended December 31, 2000 was $302 million compared with $168 million for the year ended December 31, 1999. Our 2000 net income increased $134 million over 1999 primarily because of a $140 million after-tax extraordinary charge that we recorded in 1999. This charge reflected a regulatory disallowance resulting from an ACC-approved Settlement Agreement related to the implementation of retail electric competition. The resulting increase in our 2000 net income was partially offset by the absence of a $38 million income tax benefit from discontinued operations that we also recorded in 1999. See "Regulatory Agreements" below and Notes 1 and 3 for additional information about the 1999 Settlement Agreement and the resulting regulatory disallowance. See Note 4 for additional information about the income tax benefit from discontinued operations.

Income from continuing operations for the year ended December 31, 2000 was $302 million compared with $270 million for the year ended December 31, 1999. The year-to-year comparison benefited from strong wholesale and retail electric sales and real estate profits. These positive factors more than offset decreases resulting from the completion of ITC amortization in 1999, reductions in retail electricity prices, lower earnings from El Dorado, and miscellaneous factors. See "Regulatory Agreements" below and Note 3 for information on the price reductions. See "Regulatory Agreements" below and Note 4 for additional information about ITC amortization.

The major factors that increased (decreased) income from continuing operations were as follows:

(dollars in millions)	INCREASE (DECREASE)
Increases (decreases) in electric revenues, net of purchased power and fuel expense due to:	
Marketing and trading activities:	
Increase from generation sales other than native load due to higher market prices	$ 47
Increase in other realized marketing and trading in current period primarily due to more transactions	51
Change in prior year period mark-to-market value for gains transferred to realized margin in current period	(2)(a)
Increase in mark-to-market value related to future periods	13 (a)
Net increase in marketing and trading	109
Retail price reductions (see Note 3)	(28)
Higher retail sales primarily related to customer growth	9
Miscellaneous revenues	10
Total increase in revenues, net of purchased power and fuel expense	100
Increase in real estate contributions	13
Higher operations and maintenance expense related primarily to customer growth substantially offset by $20 million of other items recorded in 1999	(4)
Higher other net expense primarily related to El Dorado	(10)
Higher depreciation and amortization expense	(11)
Miscellaneous items, net	(3)
Net increase in income from continuing operations before income taxes	85
Higher income taxes due to higher income in 2000 and higher ITC amortization in 1999	(53)
Net increase in income from continuing operations	$ 32

(a) Essentially all of our marketing and trading activities are structured activities. This means our portfolio of forward sales positions is hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.

Electric operating revenues increased approximately $1.24 billion because of:

- changes in marketing and trading revenues ($616 million, net increase):
  - increased revenues related to generation sales other than native load as a result of higher market prices ($86 million);
  - increased realized revenues related to other marketing and trading in current period primarily due to more transactions and higher market prices ($519 million);
  - decreased prior period mark-to-market value for gains transferred to realized margin in current period ($2 million);
  - increased mark-to-market value for future periods primarily as a result of more forward sales volumes ($13 million);
- increased revenues related to increased volumes and higher market prices for other wholesale sales resulting from retail load hedging activities and miscellaneous revenues ($523 million);
- increased retail revenues primarily related to higher sales volumes due to customer growth ($127 million); and
- decreased retail revenues related to reductions in retail electricity prices ($28 million).

Purchased power and fuel expenses increased approximately $1.14 billion primarily due to:

- changes in marketing and trading purchased power and fuel costs ($507 million, increase) due to:
  - increased fuel costs related to generation sales other than native load as a result of higher fuel prices ($39 million);
  - increased fuel and purchased power costs related to other realized marketing and trading in current period primarily due to more transactions ($468 million);
- increased costs related to increased volumes and higher market prices for wholesale sales resulting from retail hedging activities ($513 million); and
- higher costs related to retail sales volumes due to customer growth and increased fuel and purchased power prices ($118 million).

The increase in real estate profits of $13 million resulted primarily from increases in sales of land and homes by SunCor.

The increase in operations and maintenance expenses of $4 million primarily related to customer growth was substantially offset by $20 million of other items recorded in 1999.

The increase in depreciation and amortization of $11 million primarily related to higher plant in service balances offset by lower regulatory asset amortization.

Net other expense decreased $10 million primarily because of changes in 2000 in the market value of El Dorado's investment in a technology-related venture capital partnership. See Note 1 for additional information about the valuation of El Dorado's investments.

Regulatory Agreements

Regulatory agreements approved by the ACC affect the results of APS' operations. The following discussion focuses on three agreements approved by the ACC, each of which included retail electricity price reductions:

- The 1999 Settlement Agreement to implement retail electric competition;
- A 1996 agreement that accelerated the amortization of APS' regulatory assets; and
- A 1994 settlement that accelerated the amortization of APS' deferred ITCs.

1999 Settlement Agreement

As part of the 1999 Settlement Agreement, APS agreed to reduce retail electricity prices for standard-offer, full-service customers with loads less than three megawatts in a series of annual decreases of 1.5% on July 1, 1999 through July 1, 2003, for a total of 7.5%. The first reduction of approximately $24 million ($14 million after income taxes) included the July 1, 1999 retail price decrease required by the 1996 regulatory agreement (see below). For customers having loads three megawatts or greater, standard-offer rates will be reduced in annual increments that total 5% in the years 1999 through 2002.

The 1999 Settlement Agreement also removed, as a regulatory disallowance, $234 million before income taxes ($183 million net present value) from ongoing regulatory cash flows. APS recorded this regulatory disallowance as a net reduction of regulatory assets and reported it as a $140 million after-tax extraordinary charge on the 1999 income statement.

Under the 1996 regulatory agreement, APS was recovering substantially all of its regulatory assets through accelerated amortization over an eight-year period that would have ended June 30, 2004. For more details, see Note 1. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

1999	2000	2001	2002	2003	1/1- 6/30 2004	TOTAL
$164	$158	$145	$115	$86	$18	$686

See Note 3 and "Business Outlook – Electric Competition (Retail)" below for additional information regarding the 1999 Settlement Agreement.

1996 Regulatory Agreement

As part of the 1996 regulatory agreement, APS reduced its retail electricity prices by 3.4% effective July 1, 1996. This reduction decreased electric revenue by about $49 million annually ($29 million after income taxes). APS also agreed to share future cost savings with its customers during the term of this agreement, which resulted in the following additional retail price reductions:

- $18 million annually ($11 million after income taxes), or 1.2%, effective July 1, 1997;
- $17 million annually ($10 million after income taxes), or 1.1%, effective July 1, 1998; and
- $11 million annually ($7 million after income taxes), or 0.7%, effective July 1, 1999 (as noted above, this reduction was included in the July 1, 1999 price reduction under the 1999 Settlement Agreement).

1994 Rate Settlement

As part of a 1994 rate settlement, APS accelerated amortization of substantially all of its ITCs over a five-year period that ended on December 31, 1999. The amortization of ITCs decreased annual consolidated income tax expense by about $24 million. Beginning in 2000, no further benefits were reflected in income tax expense related to the acceleration of the ITCs (see Note 4).

LIQUIDITY AND CAPITAL RESOURCES

Capital Needs and Resources

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the year ended December 31, 2001 and estimated capital expenditures for the next three years.

	(ACTUAL)	(ESTIMATED)		
(dollars in millions)	**2001**	2002	2003	2004
APS				
Delivery	**$ 354**	$ 349	$ 271	$ 280
Existing generation (a)	**117**	149	–	–
Subtotal	**471**	498	271	280
Pinnacle West Energy (b)				
Generation expansion	**533**	411	255	113(e)
Existing generation(a)	**–**	–	107	99
Subtotal	**533**	411	362	212
SunCor (c)	**80**	79	48	52
Other (d)	**45**	35	15	16
Total	**$1,129**	$ 1,023	$ 696	$ 560

(a) Pursuant to the 1999 Settlement Agreement, APS is required to transfer its competitive electric assets and services no later than December 31, 2002.

(b) See Note 10 for further discussion of Pinnacle West Energy's generation expansion program and "Capital Resources and Cash Requirements – Pinnacle West Energy" below.

(c) Consists primarily of capital expenditures for land development and retail and office building construction reflected in the "Increase in real estate investments" in the consolidated statements of cash flows.

(d) Primarily Pinnacle West and APSES.

(e) This amount does not include an expected reimbursement by Southern Nevada Water Authority (SNWA) of $100 million of these costs in 2004 in exchange for SNWA's purchase of a 25% interest in the Silverhawk project at that time.

APS and the other Palo Verde participants are currently considering issues related to replacement of the steam generators in Units 1 and 3. Although a final determination of whether Units 1 and 3 will require steam generator replacement to operate over their current full licensed lives has not yet been made, APS and the other participants have approved an expenditure in 2002 to procure long lead-time materials for fabrication of a spare set of steam generators for either Unit 1 or 3. APS' portion of this expenditure is approximately $7 million and is included in the estimated expenditures above.

This action will provide the Palo Verde participants an option to replace the steam generators at either Unit 1 or 3 as early as fall 2005 should they ultimately choose to do so. If the participants decide to proceed with steam generator replacement at both Units 1 and 3, APS has estimated that its portion of the fabrication and installation costs and associated power uprate modifications would be approximately $130 million over the next seven years, which will be funded with internally generated cash or external financings.

Existing generation capital expenditures are comprised of multiple improvements for our existing fossil and nuclear plants. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment such as turbines, boilers, and environmental equipment. The increase in this category in 2002 is due primarily to Four Corners and various gas-fired units. The increased work on equipment is due to higher use of the units and also a stack replacement project for Four Corners Units 1 and 2. The existing generation also contains nuclear fuel expenditures of approximately $30 million annually in 2002, 2003 and 2004.

Delivery capital expenditures are comprised of transmission and distribution (T&D) infrastructure additions and upgrades, capital replacements, new customer construction, and related information systems and facility costs. Examples of the types of projects included in the forecast include T&D lines and substations, line extensions to new residential and commercial developments, and upgrades to customer information systems. In addition, we began several major transmission projects in 2001. These projects are periodic in nature and are driven by strong regional customer growth. We expect to spend about $150 million on major transmission projects during the 2002-2004 time frame.

Capital Resources and Cash Requirements

The following table summarizes cash commitments for the year ended December 31, 2001 and estimated commitments for the next three years:

	(ACTUAL)	(ESTIMATED)		
(dollars in millions)	**2001**	2002	2003	2004
Long-term debt payments (see Note 6)				
APS	$ **384**	$ 247	$ –	$ 205
Pinnacle West	**213**	–	276	216
SunCor	**24**	–	42	86
Total long-term debt payments	**621**	247	318	507
Operating leases payments (see Note 8)	**67**	68	66	65
Fuel and purchase power commitments (see Note 10)	**374**	270	124	80
Total cash commitments	**$ 1,062**	$ 585	$ 508	$ 652

Pinnacle West had available lines of credit in the amount of $250 million at December 31, 2001. APS had lines of credit available in the amount of $250 million at December 31, 2001. There was no outstanding balance on either the Pinnacle West or APS lines of credit at December 31, 2001. Pinnacle West and APS project that these lines of credit will be available over the next three years. The lines of credit are anticipated to be renewed at their expiration dates. See Note 5 for further information on Pinnacle West's and APS' lines of credit.

SunCor had an available line of credit at December 31, 2001 in the amount of $140 million. This line of credit had an outstanding balance at December 31, 2001 of $128 million. SunCor projects that this line of credit will be available over the next three years. SunCor also anticipates renewing the line of credit at its expiration date. See Note 5 for further details on SunCor's line of credit.

The parent company has issued parental guarantees and obtained surety bonds on behalf of its unregulated subsidiaries, primarily for Pinnacle West Energy's expansion plans, which are reflected in the capital expenditure table above, and APSES' retail and energy business.

APS has obtained approximately $500 million in letters of credit primarily to provide credit support for its variable rate tax-exempt bonds and its Palo Verde sale-leaseback transactions. Pinnacle West has obtained approximately $40 million in letters of credit to provide credit support for Pinnacle West Energy's generation expansion plans.

Pinnacle West and APS do not have ratings triggers in any of their debt agreements. Ratings triggers are provisions that would result in the acceleration of repayment obligations based upon a credit rating agency downgrade. Although those rating triggers appear in certain power marketing and trading agreements, their financial impacts are not expected to be significant.

APS' first mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel, transportation equipment and other excluded assets). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 2001.

See the Company's consolidated debt structure in Note 6. The parent company and our subsidiaries' capital needs and resources are described as follows.

Pinnacle West (Parent Company)

During the past three years, our primary cash needs were for:

- dividends to our shareholders;
- equity infusions into our subsidiaries;
- interest payments; and
- optional and mandatory repayment of principal on our long-term debt.

The equity infusions into our subsidiaries during the past three years included $50 million invested in APS in 1999.

This investment completed the funding of Pinnacle West's commitment under the 1996 regulatory agreement (see Note 3) to infuse $50 million a year into APS ($200 million total) from 1996 through 1999. The investments into Pinnacle West Energy were $484 million in 2001 and $193 million in 2000 to fund portions of its capital expenditures for its generation expansion program.

Over the next three years, we anticipate that our cash needs will fall into these same categories. We expect our equity infusions into Pinnacle West Energy to continue as it invests in additional generating facilities (see Note 10) until it begins to finance its own construction needs.

Our primary sources of cash are dividends from APS, our marketing and trading operations, and external financing. For the years 1999 through 2001, total dividends from APS were $510 million.

Our long-term debt at December 31, 2001 was $576 million compared with $238 million at December 31, 2000. We had $235 million of borrowings outstanding on our commercial paper at December 31, 2001. Our debt repayment requirements for the parent company for the next three years are approximately: zero in 2002, $276 million in 2003, and $216 million in 2004.

On February 8, 2002, we issued $215 million of our 4.5% Notes due 2004.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. APS pays for its capital requirements with cash from operations and, to the extent necessary, external financing. APS pays for its dividends to Pinnacle West with cash from operations.

During the period from 1999 through 2001, APS paid for substantially all of its capital expenditures with cash from operations. APS expects to do so in 2002 through 2004 with cash from operations and its own debt issuances.

See the capital expenditure table above for additional information regarding actual capital expenditures in 2001 and projected capital expenditures for the next three years.

During 2001, APS redeemed approximately $384 million of long-term debt, including premiums, with cash from operations and from the issuance of long- and short-term debt. APS' long-term debt redemption requirements for the next three years are approximately: $247 million in 2002; zero in 2003; and $205 million in 2004. Based on market conditions and call provisions, APS may make optional redemptions of long-term debt from time to time.

As of December 31, 2001, APS had credit commitments from various banks totaling about $250 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At the end of 2001, APS had about $171 million of commercial paper outstanding and no bank borrowings.

APS' long-term debt was approximately $2.1 billion at December 31, 2001 and 2000 (see Note 6).

Although ACC financing orders establish maximum amounts of additional debt that APS may issue, APS does not expect these orders to limit its ability to meet its capital requirements.

On March 1, 2002, APS issued $375 million of 6.50% Notes due 2012. On March 15, 2002, APS announced the redemption on April 15, 2002 of approximately $125 million of its First Mortgage Bonds, 8.75% series due 2024.

Pinnacle West Energy

See Note 10 for a discussion of Pinnacle West Energy's generation expansion plans. Pinnacle West Energy is currently funding its capital requirements through capital infusions from the parent. We finance those infusions through debt financing and internally generated cash, as Pinnacle West Energy develops and obtains additional generation assets. Pinnacle West Energy also expects to fund its capital requirements through internally generated cash and its own debt issuances. See the Capital Expenditures Table above for actual capital expenditures in 2001 and projected capital expenditures for the next three years.

Other Subsidiaries

During the past three years, both SunCor and El Dorado funded all of their cash requirements with cash from operations and, in the case of SunCor, its own external financings. APSES funded its cash requirements with cash infusions from Pinnacle West.

SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the Capital Expenditures Table above for actual capital expenditures in 2001 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements with cash from operations and external financings.

As of December 31, 2001, SunCor had a $140 million line of credit, under which $128 million of borrowings were outstanding. SunCor's debt repayment obligations for the next three years are approximately: zero in 2002; $42 million in 2003; and $86 million in 2004.

El Dorado does not have any capital requirements over the next three years. El Dorado intends to focus on prudently realizing the value of its existing investments. El Dorado's future investments are expected to be related to the energy sector.

APSES capital expenditures and other cash requirements are increasingly funded by operations, with some funding from cash infused by Pinnacle West. See the Capital Expenditures Table above regarding APSES' capital expenditures.

See Notes 5 and 6 for additional information about outstanding lines of credit and long-term debt obligations.

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with generally accepted accounting principles (GAAP), management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, and related disclosures at the date of the financial statements and during the reporting period. Some of those judgements can be subjective and complex, and actual results could differ from those estimates. Our most critical accounting policies include the determination of the appropriate accounting for our derivative instruments, mark-to-market accounting and the impacts of regulatory accounting on our financial statements. See Note 1 for a discussion of these critical accounting policies.

OTHER ACCOUNTING MATTERS

We prepare our financial statements in accordance with Statement of Financial Accounting Standards (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 of the 1999 Settlement Agreement (see "Regulatory Agreements" above and Note 3), we discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, we reported a regulatory disallowance ($140 million after income taxes) as an extraordinary charge on the 1999 consolidated income statement. See Note 1 for additional information on regulatory accounting and Note 3 for additional information on the 1999 Settlement Agreement.

Effective January 1, 2001, we adopted 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 sheets and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in income or stockholders' equity (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. Hedge effectiveness is measured based on the relative changes in fair value between the derivative contract and the hedged commodity over time. Any change in the fair value resulting from ineffectiveness is recognized immediately in net income. This new standard may result in additional volatility in our net income and other comprehensive income.

As a result of adopting SFAS No. 133 in 2001, we recorded a $15 million after-tax loss in consolidated net income and a $72 million after-tax gain in equity (as a component of other comprehensive income), both as a cumulative effect of a change in accounting principle. The loss primarily resulted from electricity options contracts. The gain resulted from unrealized gains on cash flow hedges. See Note 17 for further information on accounting for derivatives under SFAS No. 133, including discussion on new guidance effective on April 1, 2002.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This Statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes Accounting Principles Board Opinion No. 17, "Intangible Assets." This standard is effective for the year beginning January 1, 2002. We have no goodwill recorded in our consolidated balance sheets. The impacts of this new standard are not material to our consolidated financial statements.

The FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" in August 2001. The standard requires the estimated present value of the cost of decommissioning and certain other removal costs to be recorded as a liability, along with an offsetting plant asset when a decommissioning or other removal obligation is incurred. We are currently evaluating the impacts of the new standard, which is effective for the year beginning January 1, 2003.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," and the accounting and reporting provisions for the disposal of a segment of a business. SFAS No. 144 is effective for the year beginning January 1, 2002. This standard does not impact our financial statements at adoption.

In 2001, the American Institute of Certified Public Accountants (AICPA) issued an exposure draft of a proposed Statement of Position (SOP), "Accounting for Certain Costs Related to Property, Plant and Equipment (PP&E)." This proposed SOP would create a project timeline framework for capitalizing costs related to PP&E construction, require that PP&E assets be accounted for at the component level and require administrative and general cost incurred in support of capital projects to be expensed in the current period. The AICPA plans to issue the final SOP in the fourth quarter of 2002. We are currently evaluating the impacts of the proposed SOP.

In 1986, APS entered into agreements with three separate special purpose entity (SPE) lessors in order to sell and lease back interests in Palo Verde Unit 2 (See Note 8). The leases are accounted for as operating leases in accordance with GAAP. In February 2002, the FASB discussed issues related to special purpose entities. It is expected that FASB will issue additional guidance on accounting for SPEs later this year. As a result of future FASB actions, we may be required to consolidate the Palo Verde SPEs in our financial statements. If consolidation is required, the assets and liabilities of the SPEs that relate to the sale-leaseback transactions would be reflected on our consolidated balance sheets. The SPE debt that is not reflected on our consolidated balance sheets is approximately $300 million at December 31, 2001. Rating agencies have already considered this debt when evaluating our credit ratings.

BUSINESS OUTLOOK

Financial Outlook

We currently believe that it will be a challenge for us in 2002 to repeat our 2001 earnings. For 2001, our reported income from continuing operations was $327 million, or $3.85 per diluted share of common stock, and included charges totaling $21 million before income taxes, or $0.15 per diluted share, that we do not expect to recur related to our exposure to Enron and its affiliates. Our earnings in 2002 are expected to be negatively affected by a significant decrease in the earnings contribution from our marketing and trading activities and retail electricity price decreases. These negative factors are expected to be substantially offset in 2002 by the absence of significant expenses for reliability and power plant outages that we incurred in 2001 that we do not expect to recur in 2002 and by retail customer growth, although the pace of growth is expected to be slower than in the past. These factors are described in more detail below.

In 2001, our marketing and trading activities contributed about one-half of our income from continuing operations before the Enron related charges. These activities are currently expected to provide about one-fourth of our earnings in 2002. The drivers of such reduced earnings contributions from our marketing and trading activities in 2002 are significant reductions in: wholesale market prices for electricity that occurred during 2001; wholesale market liquidity, which affects our ability to buy and resell electricity; and market volatility, which affects our ability to capture profitable structured trading activities. These reductions in regional market factors were due, in large part, to conservation measures in California and throughout the West; more generating plants in service in the West; lower natural gas prices; and the price mitigation plan that took effect in June 2001 as mandated by the FERC.

During 2001, in order to meet highest customer demand in APS' history, we incurred significant expenses for our summer reliability program and for higher replacement power costs related to power plant outages. These efforts cost approximately $140 million before income taxes, which is not expected to be repeated in 2002. See "Results of Operations – 2001 Compared with 2000" above.

We estimate our retail customer growth in 2002 to be 3.2%, which is slower than the pace of growth in recent years, although still about three times the national average. Our customer growth in 2001 was 3.7%. We expect the customer growth rate to be weak in the first two quarters of 2002, then begin a rebound. Our current estimate for customer growth in 2003 and 2004 is between 3.5% and 4.0% annually.

The retail price decreases are described above in "Results of Operations – Regulatory Agreements."

As of December 31, 2001, the indicated annual dividend rate on our common stock was $1.60 per share. Since 1994, we have increased the dividend on our common stock ten cents per share per year. We currently plan to continue annual dividend increases of relatively consistent amounts, which would continue dividend growth at a pace above the industry average.

The foregoing discussion of future expectations is forward-looking information. Actual results may differ materially from expectations. See "Forward-Looking Statements" below.

Other Factors Affecting Our Financial Outlook

Competition and Industry Restructuring

Electric Competition (Wholesale)

The FERC regulates rates for wholesale power sales and transmission services. Our marketing and trading division sells in the wholesale market APS and Pinnacle West Energy generation production output that is not needed for APS' native load and, in doing so, competes with other utilities, power marketers, and independent power producers. Wholesale market prices significantly fell during 2001 and remain low for the reasons discussed under "Financial Outlook" above. We cannot predict whether these lower prices will continue, or whether changes in various factors that affect demand and capacity, including regulatory actions, will cause the market prices to rise during 2002 or thereafter.

Electric Competition (Retail)

On September 21, 1999, the ACC approved Rules that provide a framework for the introduction of retail electric competition in Arizona. A Maricopa County, Arizona, Superior Court later found the Rules unlawful and unconstitutional; however, the Rules remain in effect pending the outcome of appeals. See "Retail Electric Competition Rules" in Note 3 for additional information about the Rules and the outstanding legal challenges to the Rules.

Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is 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 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, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Energy prices in the western U.S. 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 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 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power.

On September 23, 1999, the ACC approved a comprehensive 1999 Settlement Agreement among APS and various parties related to the implementation of retail electric competition in Arizona. See "1999 Settlement Agreement" in Note 3 for additional information about the 1999 Settlement Agreement, including the recent resolution of legal challenges to the 1999 Settlement Agreement.

Under the Rules, as modified by the 1999 Settlement Agreement, APS is required to transfer all of its competitive electric assets and services either to an unaffiliated party or to a separate corporate affiliate no later than December 31, 2002. Consistent with that requirement, APS has been addressing the legal and regulatory requirements necessary to complete the transfer of its generation assets to Pinnacle West Energy on or before that date. In anticipation of APS' transfer of generation assets, Pinnacle West Energy has completed, and is in the process of developing and planning, various generation expansion projects so that APS can reliably meet the energy requirements of its Arizona customers.

Following APS' transfer of its fossil-fueled generation assets and the receipt of certain regulatory approvals, Pinnacle West Energy expects to sell its power at wholesale to our marketing and trading division, which, in turn, is expected to sell power to APS and to non-affiliated power purchasers. In a filing with the ACC on October 18, 2001, APS requested the ACC to:

- grant APS a partial variance from an ACC Rule that would obligate APS to acquire all of its customers' standard-offer generation requirements from the competitive market (with at least 50% of those requirements coming from a "competitive bidding" process) starting in 2003; and
- approve as just and reasonable a long-term purchase power agreement between APS and Pinnacle West.

APS requested these ACC actions to ensure ongoing reliable service to APS standard-offer, full-service customers in a volatile generation market and to recognize Pinnacle West Energy's significant investment to serve APS load. See "Proposed Rule Variance and Purchase Power Agreement" in Note 3 for additional information about APS' October 2001 ACC filing.

On February 8, 2002, the ACC's Chief ALJ issued a procedural order which consolidated the ACC docket relating to APS' October, 2001 filing with several other pending ACC dockets, including a "generic" docket request by the ACC Chairman to "determine if changed circumstances require the [ACC] to take another look at restructuring in Arizona." Although the order consolidates several dockets, it states that a hearing on the APS matter will commence on April 29, 2002. The order went on to state that, contrary to APS' position, the ALJ was construing the October, 2001 filing as a request by APS to amend the 1999 ACC order that approved the 1999 Settlement Agreement.

On March 22, 2002, the ACC Staff issued a report to the ACC recommending that the ACC address the following issues in the generic docket:

- The extent and manner of the ACC's involvement in monitoring market conditions and/or mitigating the development of market power for generation and transmission;
- The lack of guidance in the Rules regarding the mechanics of the "competitive bidding process" referenced above;
- The consideration of alternatives to the transfer of generation assets required by the Rules (the ACC Staff stated that such transfers would be "unwise" at the present time and recommended that "all transfer and separation of utilities' assets be stayed pending the completion of the generic docket");
- The consideration of transmission constraints that could impact the development of the wholesale power market;
- The reassessment of adjustor mechanisms for standard-offer rates in light of problems with the development of a wholesale power market; and
- The adequacy of customer "shopping credits" in the context of the development of a competitive retail market (a shopping credit is the cost a customer does not pay to a utility distribution company if the customer obtains generation from another party).

Although not a specific ACC Staff recommendation, the report was also critical of certain aspects of the proposed purchase power agreement between APS and Pinnacle West.

A modification to the Rules or the 1999 Settlement Agreement as a result of the consolidated docket could, among other things, adversely affect APS' ability to transfer its generation assets to Pinnacle West Energy by December 31, 2002. We cannot predict the outcome of the consolidated docket or its effect on the specific requests in APS' October 2001 filing, the existing Arizona electric competition rules, or the 1999 Settlement Agreement.

As a result of the foregoing matters, as well as energy market developments, including those relating to California's failed deregulation efforts and to Enron's recent bankruptcy filing, electric utility restructuring is in a state of flux in the western United States, including Arizona, and around the country.

Generation Expansion

See Note 10 for information regarding our generation expansion plans. The planned additional generation is expected to increase revenues, fuel expenses, operating expenses, and financing costs.

California Energy Market Issues

See Note 10 for information regarding California energy market issues.

Factors Affecting Operating Revenues

Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona, and from competitive retail and wholesale bulk power markets in the western United States. These revenues are expected to be affected by electricity sales volumes related to customer mix, customer growth and average usage per customer, as well as electricity prices and variations in weather from period to period.

In APS' regulated retail market area, APS will provide electricity services to standard-offer, full-service customers and to energy delivery customers who have chosen another provider for their electricity commodity needs (unbundled customers). Customer growth in APS' service territory averaged about 4% a year for the three years 1999 through 2001; we currently expect customer growth to be about 3.2% in 2002 and between 3.5% and 4.0% a year in 2003 and 2004. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 5.5% a year in 2002 through 2004, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph apply to energy delivery customers. As industry restructuring evolves in the regulated market area, we cannot predict the number of APS' standard-offer customers that will switch to unbundled service. As previously noted, under the 1999 Settlement Agreement, we have annual retail electricity price reductions of 1.5% through July 1, 2003 (see Note 3).

Competitive sales of energy and energy-related products and services are made by APSES in western states that have opened to competitive supply. Such activities currently are not material to our consolidated financial results.

Other Factors Affecting Future Financial Results

Purchased power and fuel costs are impacted by our electricity sales volumes, existing contracts for generation fuel and purchased power, our power plant performance, prevailing market prices, new generating plants being placed in service and our hedging program for managing such costs.

Operations and maintenance expenses are expected to be affected by sales mix and volumes, power plant operations, inflation, outages and other factors.

Depreciation and amortization expenses are expected to be affected by net additions to existing utility plant and other property, changes in regulatory asset amortization, and our generation expansion program. See Note 1 for the regulatory asset amortization that is being recorded in 1999 through 2004 pursuant to the 1999 Settlement Agreement. Also, see Note 1 regarding current depreciation rates.

Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in service and under construction. The average property tax rate for APS, which currently owns the majority of our property was 9.32% for 2001 and 9.16% for 2000. We expect property taxes to increase primarily due to our generation expansion program and our additions to existing facilities.

Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our generation expansion program and our internally-generated cash flow.

The annual earnings contribution from APSES is expected to be modest, yet positive, over the next several years due primarily to a number of retail electricity contracts in California. APSES' pretax losses were $10 million in 2001 and $13 million in 2000.

The annual earnings contribution from SunCor is expected to remain modest over the next several years. SunCor's earnings were $3 million in 2001, $11 million in 2000 and $6 million in 1999.

El Dorado's historical results are not necessarily indicative of future performance for El Dorado. El Dorado's strategies focus on prudently realizing the value of its existing investments. Any future investments are expected to be related to the energy sector. See Note 1 for additional information regarding El Dorado.

We cannot accurately predict the impact of full retail competition on our financial position, cash flows, results of operations, or liquidity. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a restructured industry.

Our financial results may be affected by the application of SFAS No. 133. See "Critical Accounting Policies" above and Note 17 for further information.

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

MARKET RISKS

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

Interest Rate and Equity Risk

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our nuclear decommissioning trust fund (see Note 11). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The nuclear decommissioning fund also has risks associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

The tables below present contractual balances of our long-term debt and commercial paper at the expected maturity dates as well as the fair value of those instruments on December 31, 2001 and 2000. The interest rates presented in the tables below represent the weighted average interest rates for the years ended December 31, 2001 and 2000.

EXPECTED MATURITY/PRINCIPAL REPAYMENT (dollars in thousands)

	SHORT-TERM DEBT		VARIABLE-RATE LONG-TERM DEBT		FIXED-RATE LONG-TERM DEBT	
December 31, 2001	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT
2002	4.01%	$ 405,762	7.76%	$ 207	8.10%	$ 125,933
2003		–	4.75%	292,912	6.87%	25,829
2004		–	5.32%	85,601	6.08%	205,677
2005		–	7.70%	294	7.59%	400,380
2006		–	7.30%	3,018	6.48%	384,085
Years thereafter		–	2.63%	480,740	6.73%	799,808
Total		$ 405,762		$ 862,772		$ 1,941,712
Fair Value		$ 405,762		$ 862,772		$ 1,963,389

EXPECTED MATURITY/PRINCIPAL REPAYMENT (dollars in thousands)

	SHORT-TERM DEBT		VARIABLE-RATE LONG-TERM DEBT		FIXED-RATE LONG-TERM DEBT	
December 31, 2000	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT
2001	6.64%	$ 82,775	7.23%	$ 438,203	6.63%	$ 25,266
2002		–	8.62%	36,890	8.13%	125,000
2003		–	8.61%	73,578	6.89%	25,443
2004		–	8.87%	268	6.17%	205,000
2005		–	8.89%	294	7.28%	400,000
Years thereafter		–	4.13%	483,790	7.47%	610,813
Total		$ 82,775		$ 1,033,023		$ 1,391,522
Fair Value		$ 82,775		$ 1,033,023		$ 1,422,014

Commodity Price Risk

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions 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 commodity.

In addition, subject to specified risk parameters established by the Board of Directors and monitored by the Energy Risk Management Committee, we engage in trading activities intended to profit from market price movements. In accordance with Emerging Issues Task Force (EITF) 98-10. "Accounting For Contracts Involved in Energy Trading and Risk Management Activities," such trading positions are marked-to-market. These trading activities are part of our marketing and trading activities and are reflected in the marketing and trading revenues and expenses.

The following schedule shows the changes in mark-to-market of our trading positions during the years ended December 31, 2001 and 2000:

(dollars in millions)	2001	2000
Mark-to-market of net trading positions at beginning of year	$ 12	$ –
Prior period marked-to-market gains realized during the year	(1)	(2)
Change in marked-to-market gains for future period deliveries	127	14
Mark-to-market of net trading positions at end of year	$ 138	$ 12

Net gains at inception include a reasonable marketing margin and were approximately $3 million in 2001 and $2 million in 2000. See Note 17 for disclosure of risk management activities recorded on the consolidated balance sheets.

The table below shows the maturities of our trading positions as of December 31, 2001 in millions of dollars by the type of valuation that is performed to calculate the fair value of the contract. In addition, see Note 1 for more discussion on our valuation methods.

SOURCE OF FAIR VALUE	2002	2003-2004	2005-2006	YEARS THEREAFTER	TOTAL FAIR VALUE
Prices actively quoted	$ (13)	$ 4	$ 2	$ –	$ (7)
Prices provided by other external sources	(12)	(8)	(4)	–	(24)
Prices based on models and other valuation methods	68	50	39	12	169
Total by maturity	$ 43	$ 46	$ 37	$ 12	$ 138

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management and trading assets and liabilities included on the consolidated balance sheets at December 31, 2001 and 2000.

(dollars in millions) COMMODITY	DECEMBER 31, 2001 GAIN / (LOSS) PRICE UP 10%	DECEMBER 31, 2001 GAIN / (LOSS) PRICE DOWN 10%	DECEMBER 31, 2000 GAIN / (LOSS) PRICE UP 10%	DECEMBER 31, 2000 GAIN / (LOSS) PRICE DOWN 10%
Trading (a):				
Electric	**$ (3)**	**$ 3**	$ 2	$ (2)
Natural gas	**(1)**	**1**	(1)	1
Other	**–**	**2**	–	–
System (b):				
Natural gas hedges	**23**	**(23)**	28	(28)
Total	**$ 19**	**$ (17)**	$ 29	$ (29)

(a) Essentially all of our marketing and trading activities are structured activities. This means our portfolio of forward sales positions is hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.
(b) These contracts are hedges of our forecasted purchases of natural gas. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged.

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including one counterparty for which a worst case exposure represents approximately 50% of our $267 million of risk management and trading assets as of December 31, 2001. We use a risk management process to assess and monitor the financial exposure of this 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 counterparty 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. Credit reserves are established representing our estimated credit losses on our overall exposure to counterparties. See Note 1 for a discussion of our credit reserve policy.

FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements based on current expectations and we assume no obligation to update these statements. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and APS' October 2001 ACC filing; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including the price mitigation plan adopted by the FERC in June 2001; regional economic and market conditions, including the California energy situation and completion of generation construction in the region, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital; weather variations affecting local and regional customer energy usage; conservation programs; power plant performance; the successful completion of our generation expansion program; regulatory issues associated with generation expansion, such as permitting and licensing; our ability to compete successfully outside traditional regulated markets (including the wholesale market); technological developments in the electric industry; and the strength of the real estate market in SunCor's market areas, which include Arizona, New Mexico and Utah.

These factors and the other matters discussed above may cause future results to differ materially from historical results, or from results or outcomes we currently expect or seek.

REPORT OF MANAGEMENT AND INDEPENDENT AUDITOR'S REPORT

REPORT OF MANAGEMENT

The responsibility for the integrity of our financial information rests with management, which has prepared the accompanying financial statements and related information. This information was prepared in accordance with generally accepted accounting principles as appropriate in the circumstances, and based on management's best estimates and judgments. These financial statements have been audited by independent auditors and their report is included.

Management maintains and relies upon systems of internal control. A limiting factor in all systems of internal control is that the cost of the system should not exceed the benefits to be derived. Management believes that our system provides the appropriate balance between such costs and benefits.

Periodically the internal control system is reviewed by both our internal auditors to test for compliance and our independent auditors in conjunction with their audit of our financial statements. Reports issued by the internal auditors are released to management, and such reports or summaries thereof are transmitted to the Audit Committee of the Board of Directors and the independent auditors on a timely basis. By letter dated February 8, 2002, to the Audit Committee, our independent auditors confirmed that they are independent accountants with respect to us within the meaning of the Securities Act and the requirements of the Independence Standards Board.

The Audit Committee, composed solely of outside directors, meets periodically with the internal auditors and independent auditors (as well as management) to review the work of each. The internal auditors and independent auditors have free access to the Audit Committee, without management present, to discuss the results of their audit work.

Management believes that our systems, policies and procedures provide reasonable assurance that operations are conducted in conformity with the law and with management's commitment to a high standard of business conduct.

William J. Post Chairman and Chief Executive Officer	Chris N. Froggatt Vice President and Controller

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2001. Our audits also included the financial statement schedule listed in the Index at Item 14. These financial statements and the financial statement schedule are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and subsidiaries at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 17 to the financial statements, in 2001 Pinnacle West Capital Corporation changed its method of accounting for derivatives and hedging activities in order to comply with the provisions of Statement of Financial Accounting Standards No. 133.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona
February 8, 2002 (March 22, 2002, as to Note 18)

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

year ended December 31,	2001	2000	1999
OPERATING REVENUES			
Electric	$ 4,382,465	$ 3,531,810	$ 2,293,184
Real estate	168,908	158,365	130,169
Total	4,551,373	3,690,175	2,423,353
OPERATING EXPENSES			
Purchased power and fuel	2,664,218	1,932,792	793,931
Operations and maintenance	530,095	450,205	446,173
Real estate operations	153,462	134,422	119,516
Depreciation and amortization	427,903	431,229	419,842
Taxes other than income taxes	101,068	99,780	96,606
Total	3,876,746	3,048,428	1,876,068
OPERATING INCOME	674,627	641,747	547,285
OTHER INCOME (EXPENSE)			
Preferred stock dividend requirements of APS	–	–	(1,016)
Net other income and expense	(5,765)	(406)	10,573
Total	(5,765)	(406)	9,557
INTEREST EXPENSE			
Interest charges	175,822	166,447	157,142
Capitalized interest	(47,862)	(21,638)	(11,664)
Total	127,960	144,809	145,478
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	540,902	496,532	411,364
INCOME TAXES	213,535	194,200	141,592
INCOME FROM CONTINUING OPERATIONS	327,367	302,332	269,772
Income tax benefit from discontinued operations	–	–	38,000
Extraordinary charge – net of income taxes of $94,115	–	–	(139,885)
Cumulative effect of a change in accounting for derivatives – net of income taxes of $9,892	(15,201)	–	–
NET INCOME	$ 312,166	$ 302,332	$ 167,887
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – BASIC	84,718	84,733	84,717
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – DILUTED	84,930	84,935	85,009
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Continuing operations – basic	$ 3.86	$ 3.57	$ 3.18
Net income – basic	3.68	3.57	1.98
Continuing operations – diluted	3.85	3.56	3.17
Net income – diluted	3.68	3.56	1.97
DIVIDENDS DECLARED PER SHARE	$ 1.525	$ 1.425	$ 1.325

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (dollars in thousands)

December 31,	2001	2000
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 28,619	$ 10,363
Customer and other receivables – net	367,241	513,822
Accrued utility revenues	76,131	74,566
Materials and supplies (at average cost)	81,215	71,966
Fossil fuel (at average cost)	27,023	19,405
Deferred income taxes (Note 4)	–	5,793
Assets from risk management and trading activities (Note 17)	66,973	17,506
Other current assets	80,203	80,492
Total current assets	727,405	793,913
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Notes 1 and 6)	418,673	371,323
Assets from risk management and trading activities – long-term (Note 17)	200,351	32,955
Other assets	321,024	299,128
Total investments and other assets	940,048	703,406
PROPERTY, PLANT AND EQUIPMENT (NOTES 1, 6, 8 AND 9)		
Plant in service and held for future use	8,203,888	7,809,566
Less accumulated depreciation and amortization	3,378,089	3,188,302
Total	4,825,799	4,621,264
Construction work in progress	1,032,234	464,540
Nuclear fuel, net of accumulated amortization of $56,836 and $61,256	49,282	47,389
Net property, plant and equipment	5,907,315	5,133,193
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	342,383	469,867
Other deferred debits	64,597	62,606
Total deferred debits	406,980	532,473
TOTAL ASSETS	$ 7,981,748	$ 7,162,985

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (dollars in thousands)

December 31,	2001	2000
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 269,124	$ 375,805
Accrued taxes	96,729	89,246
Accrued interest	48,806	42,954
Short-term borrowings (Note 5)	405,762	82,775
Current maturities of long-term debt (Note 6)	126,140	463,469
Customer deposits	30,232	26,189
Deferred income taxes (Note 4)	3,244	–
Liabilities from risk management and trading activities (Note 17)	35,994	37,179
Other current liabilities	74,898	73,681
Total current liabilities	1,090,929	1,191,298
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	2,673,078	1,955,083
DEFERRED CREDITS AND OTHER		
Liabilities from risk management and trading activities – long-term (Note 17)	207,576	14,711
Deferred income taxes (Note 4)	1,064,993	1,143,040
Unamortized gain – sale of utility plant (Note 8)	64,060	68,636
Other	381,789	407,503
Total deferred credits and other	1,718,418	1,633,890
COMMITMENTS AND CONTINGENCIES (NOTES 3, 10 AND 11)		
COMMON STOCK EQUITY		
Common stock, no par value; authorized 150,000,000 shares; issued and outstanding 84,824,947 at end of 2001 and 2000	1,531,038	1,532,831
Retained earnings	1,032,850	849,883
Accumulated other comprehensive loss	(64,565)	–
Total common stock equity	2,499,323	2,382,714
TOTAL LIABILITIES AND EQUITY	$ 7,981,748	$ 7,162,985

CONSOLIDATED STATEMENTS OF CASH FLOWS (dollars in thousands)

year ended December 31,	2001	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	$ 327,367	$ 302,332	$ 269,772
Items not requiring cash			
Depreciation and amortization	427,903	431,229	419,842
Nuclear fuel amortization	28,362	30,083	31,371
Deferred income taxes – net	(16,939)	(38,625)	(43,886)
Deferred investment tax credit	(264)	740	(23,514)
Mark-to-market gains – trading	(125,521)	(11,752)	(975)
Mark-to-market gains – system	(8,052)	–	–
Changes in current assets and liabilities			
Customer and other receivables – net	146,581	(269,223)	(10,723)
Accrued utility revenues	(1,565)	(1,647)	(5,179)
Materials, supplies and fossil fuel	(16,867)	475	(8,794)
Other current assets	289	(37,436)	(12,968)
Accounts payable	(127,782)	193,502	28,193
Accrued taxes	7,483	18,736	12,591
Accrued interest	5,852	9,701	1,387
Other current liabilities	5,260	98,493	14,047
Change in El Dorado partnership investment	1,671	(3,773)	(25,786)
Increase in real estate investments	(44,173)	(25,937)	(12,542)
Increase in regulatory assets	(17,516)	(14,138)	(12,262)
Other – net	(21,159)	30,634	15,026
Net Cash Flow Provided By Operating Activities	570,930	713,394	635,600
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,040,585)	(658,608)	(343,448)
Capitalized interest	(47,862)	(21,638)	(11,664)
Other – net	(31,357)	(55,595)	(16,143)
Net Cash Flow Used For Investing Activities	(1,119,804)	(735,841)	(371,255)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	995,447	651,000	607,791
Short-term borrowings – net	322,987	44,475	(140,530)
Dividends paid on common stock	(129,199)	(120,733)	(112,311)
Repayment of long-term debt	(621,057)	(558,019)	(510,693)
Redemption of preferred stock	–	–	(96,499)
Other – net	(1,048)	(4,618)	(11,936)
Net Cash Flow Provided By (Used For) Financing Activities	567,130	12,105	(264,178)
NET CASH FLOW	18,256	(10,342)	167
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	10,363	20,705	20,538
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 28,619	$ 10,363	$ 20,705
Supplemental Disclosure of Cash Flow Information			
Cash paid during period for:			
Income taxes	$ 223,037	$ 219,411	$ 199,799
Interest paid, net of amounts capitalized	$ 115,276	$ 132,434	$ 141,138

See Notes to Consolidated Financial Statements.

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

years ended December 31, 2001, 2000, and 1999	COMMON STOCK	RETAINED EARNINGS	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	TOTAL
Balance at December 31,1998	$ 1,550,643	$ 612,708	$ –	$ 2,163,351
Net income		167,887		167,887
Dividends on common stock		(112,311)		(112,311)
Common stock expense	(13,194)			(13,194)
Balance at December 31, 1999	1,537,449	668,284	–	2,205,733
Net income		302,332		302,332
Dividends on common stock		(120,733)		(120,733)
Common stock expense	(4,618)			(4,618)
Balance at December 31, 2000	1,532,831	849,883	–	2,382,714
Net income		312,166		312,166
Minimum pension liability, net of $634 tax effect			(966)	(966)
Cumulative effect of change in accounting for derivatives, net of $47,404 tax effect			72,274	72,274
Unrealized loss on derivative instruments, net of $54,028 tax effect			(82,373)	(82,373)
Reclassification of net realized gain to income, net of $35,091 tax effect			(53,500)	(53,500)
Comprehensive income (loss)		312,166	(64,565)	247,601
Dividends on common stock		(129,199)		(129,199)
Common stock expense	(1,793)			(1,793)
Balance at December 31, 2001	$ 1,531,038	$ 1,032,850	$ (64,565)	$ 2,499,323

See 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, APSES, SunCor, and El Dorado. Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

APS, our major subsidiary and Arizona's largest electric utility, provides either retail or wholesale electric service to substantially all of the state, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates and, directly or through our marketing and trading division, sells and delivers electricity to wholesale customers in the western United States. During 2001, APS transferred most of its marketing and trading activities to the parent company. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we conduct our unregulated generation operations. APSES was formed in 1998 and provides 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, and Utah. El Dorado is an investment firm.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and 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 current year presentation.

Derivative Instruments

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions 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 commodity.

In addition, subject to specified risk parameters established by the Board of Directors and monitored by the ERMC, we engage in trading activities intended to profit from market price movements. If a contract was entered into for trading purposes, we account for it in accordance with EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 98-10 requires energy trading contracts to be measured at fair value as of the balance sheet date, with unrealized gains and losses included in earnings on a current basis (the mark-to-market method). See "Mark-to-Market Method" below and Note 17 for further information about our trading contracts.

We examine contracts at inception to determine the appropriate accounting treatment. If a contract is not considered energy trading we must determine if it is a derivative as defined in SFAS No. 133 (see Note 17 for further information on SFAS No. 133). If a contract does not meet the derivative criteria or if it qualifies for a SFAS No. 133 scope exception, we account for the contract using accrual accounting (this means that costs and revenues are recorded when physical delivery occurs). For contracts that qualify as a derivative and do not meet a SFAS No. 133 scope exception, we further examine the contract to determine if it will qualify for hedge accounting. If a contract does not meet the hedging criteria in SFAS No. 133, we recognize the changes in the fair value of the derivative instrument in income each period (mark-to-market). If it does qualify for hedge accounting, changes in the fair value are recognized as either an asset or liability or in stockholders' equity (as a component of accumulated other comprehensive income) depending on the nature of the hedge.

Gains and losses related to derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or fuel and purchased power expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings (deferral method). See Note 17 for further discussion on derivative accounting.

Mark-to-Market Method

Under mark-to-market accounting the purchase or sale of energy commodities are reflected at fair market value, net of reserves, with resulting unrealized gains and losses recorded as 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 shape quarterly and calendar year quotes into monthly prices based on historical relationships.

For options, long-term contracts and other contracts where price quotes are not available, we use models and other valuation methods. For illiquid or unquoted market locations, we consider the historical relationship to readily-available market quotations. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

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 reserves for a number of risks associated with the valuation of future commitments. These include reserves for liquidity and credit risks based on the financial condition of counterparties. The liquidity reserve represents the cost that would be incurred if all unmatched positions were closed-out or hedged. As we mark positions to a mid-market value this reserve adjusts the mid-market valuation to the bid or offer, after taking into consideration offsetting positions, to reflect the true cash flow that would be realized upon exiting the net position.

A credit reserve is also recorded to represent 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.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgement. Actual results could differ from the results estimated through application of these methods. However, essentially all of our marketing and trading activities are structured activities. This means our portfolio of forward sales positions is substantially hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. Our practice is to hedge within time-frames established by the ERMC.

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.

During 1997, the EITF of the FASB issued EITF 97-4. EITF 97-4 requires that SFAS No. 71 be discontinued no later than when legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated, which could result in write-downs or write-offs of physical and/or regulatory assets. Additionally, the EITF determined that regulatory assets should not be written off if they are to be recovered from a portion of the entity which continues to apply SFAS No. 71.

The 1999 Settlement Agreement was approved by the ACC in September 1999 (see Note 3 for a discussion of the agreement). Consequently, we have discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, a regulatory disallowance removed $234 million pretax ($183 million net present value) from ongoing regulatory cash flows and was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes) was reported as an extraordinary charge on the income statement during the third quarter of 1999. Prior to the 1999 Settlement Agreement, under the 1996 regulatory agreement (see Note 3), the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004.

The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

1999	2000	2001	2002	2003	1/1- 6/30 2004	TOTAL
$164	$158	$145	$115	$86	$18	$686

Regulatory assets are reported as deferred debits on the consolidated balance sheets. As of December 31, 2001 and 2000, they are comprised of the following:

(dollars in millions)	December 31, 2001	2000
Remaining balance recoverable under the 1999 Settlement Agreement (a)	$ 219	$ 364
Spent fuel storage (Note 10)	43	40
Electric industry restructuring transition costs (Note 3)	34	24
Other	46	42
Total regulatory assets	$ 342	$ 470

(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).

Regulatory liabilities are included in deferred credits and other on the consolidated balance sheets. As of December 31, 2001 and 2000, they are comprised of the following:

(dollars in millions)	December 31, 2001	2000
Deferred gains on utility property	$ 20	$ 20
Other	7	8
Total regulatory liabilities	$ 27	$ 28

The consolidated balance sheets include the amounts listed below for generation assets not subject to SFAS No. 71:

(dollars in millions)	December 31, 2001	2000
Electric plant in service and held for future use	$ 3,954	$ 3,854
Accumulated depreciation and amortization	(1,990)	(1,902)
Construction work in progress	824	304
Nuclear fuel, net of amortization	49	47

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

We charge retired utility plant, plus removal costs less salvage realized, to accumulated depreciation. See Note 2 for information on a new accounting standard that impacts accounting for removal costs.

We record depreciation on utility property on a straight-line basis. For the years 1999 through 2001 the rates, as prescribed by our regulators, ranged from a low of 1.49% to a high of 20%. The weighted-average rate was 3.40% for 2001, 3.40% for 2000, and 3.34% for 1999. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years. We expense the costs of plant outages, major maintenance and routine maintenance as incurred.

El Dorado Investments

El Dorado accounts for its investments using the equity method. Net other income has consisted primarily of El Dorado's share of the earnings of a venture capital partnership. We record our share of the earnings from the partnership as the partnership adjusts the value of its investments. In 2001, El Dorado received a distribution of securities representing substantially all of El Dorado's investment in the partnership. The securities were sold in the first quarter of 2001 and a gain was recognized in other income. The book value of El Dorado's investment in the partnership was approximately $1 million at December 31, 2001, and $7 million at December 31, 2000. El Dorado's net investment book value was approximately $10 million at December 31, 2001 and $21 million at December 31, 2000.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction of utility plants. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. Capitalized interest does not represent current cash earnings. The rate used to calculate capitalized interest was a composite rate of 6.13% for 2001, 6.62% for 2000, and 6.65% for 1999.

Revenues

We record electric operating revenues on the accrual basis, which includes estimated amounts for service rendered but unbilled at the end of each accounting period. We exclude sales taxes on electric revenues from both revenue and taxes other than income taxes. Electric revenues are recorded gross on the statements of income, with the exception of unrealized gains and losses recorded under the mark-to-market method (see discussion above). Unrealized gains and losses are recorded net in electric revenues. When the gain or loss is realized, the gross amount is recorded as electric revenue and fuel or purchased power expense in the consolidated statements of income.

Cash and Cash Equivalents

For purposes of the statement of cash flows, we consider all highly liquid debt instruments purchased with an initial maturity of three months or less to be cash equivalents.

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.

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 that is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units that it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units that it produces 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 United States Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation. See Note 10 for information about spent nuclear fuel disposal and Note 11 for information on nuclear decommissioning costs.

Income Taxes

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

Reacquired Debt Costs

For debt related to the regulated portion of APS' business, APS amortizes those gains and losses incurred upon early retirement over the remaining life of the debt. In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate 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 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 the 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.

2. ACCOUNTING MATTERS

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes APB Opinion No. 17, "Intangible Assets." This standard is effective for the year beginning January 1, 2002. We have no goodwill recorded in our consolidated balance sheets. The impacts of this new standard are not material to our financial statements.

In August 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." The standard requires the estimated present value of the cost of decommissioning and certain other removal costs to be recorded as a liability, along with an offsetting plant asset when a decommissioning or other removal obligation is incurred. We are currently evaluating the impacts of the new standard, which is effective for the year beginning January 1, 2003.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," and the accounting and reporting provisions for the disposal of a segment of a business. SFAS No. 144 is effective for the year beginning January 1, 2002. This standard does not impact our financial statements at adoption.

In 2001, the American Institute of Certified Public Accountants (AICPA) issued an exposure draft of a proposed Statement of Position (SOP), "Accounting for Certain Costs Related to Property, Plant, and Equipment." This proposed SOP would create a project timeline framework for capitalizing costs related to property, plant and equipment (PP&E) construction, which require that PP&E assets be accounted for at the component level, and require administrative and general costs incurred in support of capital projects to be expensed in the current period. The AICPA plans to issue the final SOP in the fourth quarter of 2002.

In 1986, APS entered into agreements with three separate special purpose entity (SPE) lessors in order to sell and lease back interests in Palo Verde Unit 2 (See Note 8). The leases are accounted for as operating leases in accordance with GAAP. In February 2002, the FASB discussed issues related to special purpose entities. It is expected that FASB will issue additional guidance on accounting for SPEs later this year. As a result of future FASB actions, we may be required to consolidate the Palo Verde SPEs in our financial statements. If consolidation is required, the assets and liabilities of the SPEs that relate to the sale-leaseback transactions would be reflected on our consolidated balance sheets. The SPE debt that is not reflected on our consolidated balance sheets is approximately $300 million at December 31, 2001. Rating agencies have already considered this debt when evaluating our credit ratings.

3. REGULATORY MATTERS

Electric Industry Restructuring

State

1999 Settlement Agreement. On May 14, 1999, APS entered into a comprehensive 1999 Settlement Agreement with various parties, including representatives of major consumer groups, related to the implementation of retail electric competition. On September 23, 1999, the ACC voted to approve the 1999 Settlement Agreement, with some modifications.

On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the 1999 Settlement Agreement. Each party bringing the lawsuits appealed the ACC's order approving the 1999 Settlement Agreement directly to the Arizona Court of Appeals, as provided by Arizona law. In one of the appeals, on December 26, 2000, the Arizona Court of Appeals affirmed the ACC's approval of the 1999 Settlement Agreement. This decision was not appealed and has become final. In the other appeal, on April 5, 2001, the Arizona Court of Appeals again affirmed the ACC's approval of the 1999 Settlement Agreement. The Arizona Consumers Council, which filed that appeal, petitioned the Arizona Supreme Court for review of the Court of Appeals' decision. On October 5, 2001, the Arizona Supreme Court agreed to hear the appeal on the single issue of whether the ACC could itself become a party to the 1999 Settlement Agreement by virtue of its approval of the 1999 Settlement Agreement. On December 14, 2001, the Arizona Supreme Court vacated its own October 5, 2001 order accepting jurisdiction and decided to dismiss the appeal. As a result, the judicial challenges to the 1999 Settlement Agreement have terminated. Consistent with its obligations under the 1999 Settlement Agreement, on January 7, 2002, APS and the ACC filed in Maricopa County Superior Court a stipulation to dismiss all of APS' litigation pending against the ACC. On January 15, 2002, a Maricopa County Superior Court judge issued an order dismissing such litigation.

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

- APS has reduced, and will reduce, 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% beginning July 1, 1999 through July 1, 2003, for a total of 7.5%. The first reduction of approximately $24 million ($14 million after income taxes) included the July 1, 1999 retail price decrease of approximately $11 million ($7 million after income taxes) related to the 1996 regulatory agreement. See "1996 Regulatory Agreement" below. Based on the price reductions authorized in the 1999 Settlement Agreement, there were also retail price decreases of approximately $28 million ($17 million after taxes), or 1.5%, effective July 1, 2000, and approximately $27 million ($16 million after taxes), or 1.5%, effective July 1, 2001. For customers having loads three MW or greater, standard-offer rates will be 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 will be 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 will be 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, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders.
- APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the ACC electric competition 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.
- 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 electric competition 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.
- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to the 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. APS will not be allowed to recover $183 million net present value of the above amounts. The 1999 Settlement Agreement provides that APS will have the opportunity to recover $350 million net present value 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 due to sales volume variances.

- APS will form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) its competitive electric assets and services at book value as of the date of transfer, and will complete the transfer no later than December 31, 2002. Accordingly, APS plans to complete the move of such assets and services from APS to the parent company or to Pinnacle West Energy by the end of 2002, as required, although the ACC's recent establishment of a "generic" docket to consider electric industry restructuring in Arizona and the consolidation of that docket with APS' request for approval of a PPA between Pinnacle West and APS could affect APS' ability to transfer assets to Pinnacle West Energy. APS will be allowed to defer and later collect, beginning July 1, 2004, sixty-seven percent of its costs to accomplish the required transfer of generation assets to an affiliate.

As discussed in Note 1 above, we have discontinued the application of SFAS No. 71 for our generation operations.

Proposed Rule Variance and Purchase Power Agreement. As authorized by the 1999 Settlement Agreement, APS intends to move substantially all of its generation assets to Pinnacle West Energy no later than December 31, 2002. Commencing upon the transfer of the fossil-fueled generating assets and the receipt of certain regulatory approvals, Pinnacle West Energy expects to sell its power at wholesale to Pinnacle West's marketing and trading division, which, in turn, is expected to sell power to APS and to non-affiliated power purchasers. In a filing with the ACC on October 18, 2001, APS requested the ACC to:

- grant APS a partial variance from an ACC rule that would obligate APS to acquire all of its customers' standard-offer, full-service generation requirements from the competitive market (with at least 50% of those requirements coming from a "competitive bidding" process) starting in 2003; and
- approve as just and reasonable a long-term purchase power agreement (PPA) between APS and Pinnacle West.

APS has requested these ACC actions to ensure ongoing reliable service to APS standard-offer, full-service customers in a volatile generation market and to recognize Pinnacle West Energy's significant investment to serve APS load. The following are the major provisions of the PPA:

- The PPA would run through 2015, with three optional five-year renewal terms, which renewals would occur automatically unless notice is given by either APS or Pinnacle West.
- The PPA would provide for all of APS' anticipated standard-offer generation needs, including any necessary reserves, except for (a) those provided by APS itself through renewable resources or other generation assets retained by APS; (b) amounts that APS is obligated by law to purchase from "qualified facilities" and other forms of distributed generation; and (c) any purchased power agreements that APS cannot transfer to Pinnacle West Energy.
- Pinnacle West would assume contractual responsibility for reliability and would supplement any potential shortfall even after full utilization of Pinnacle West Energy's dedicated generating resources.
- Pinnacle West would supply APS standard-offer requirements through a combination of (a) APS generation assets transferred to Pinnacle West Energy; (b) certain of Pinnacle West Energy's new Arizona generation projects to be constructed during the 2001-2004 period to reliably serve APS load requirements; (c) power procured by Pinnacle West under certain "dedicated contracts"; and (d) power procured on the open market, including a competitively-bid component described below.
- Beginning in 2003, Pinnacle West would acquire 270 MW of APS standard-offer requirements on the open market through a competitive bidding process. This competitive bid obligation would be increased by an additional 270 MW each year through 2008 (representing approximately 23% of estimated 2008 peak load).
- Pinnacle West would charge APS based on (a) a combination of fixed and variable price components for the Pinnacle West Energy assets, subject to periodic adjustment, and (b) a pass-through of Pinnacle West's costs to procure power from the remaining sources.
- The PPA would take effect on the latest of the following events: (a) transfer of non-nuclear generating assets from APS to Pinnacle West Energy; (b) ACC approval of the rule variance and the PPA; and (c) the FERC's acceptance of the PPA and the companion agreement between Pinnacle West and Pinnacle West Energy.

APS is required to transfer its competitive electric assets and services to one or more corporate affiliates on or before December 31, 2002. Consistent with that requirement, APS has been addressing the legal and regulatory requirements necessary to complete the transfer of its generation assets to Pinnacle West Energy, on or before that date. In anticipation of APS' transfer of generation assets, Pinnacle West Energy has completed, and is in the process of developing and planning, various generation expansion projects so that APS can reliably meet the energy requirements of its Arizona customers.

By letter dated January 14, 2002, the Chairman of the ACC stated that "the [ACC's] Electric Competition Rules, along with the Settlement Agreements approved for APS and [Tucson Electric Company], establish the framework for the transition to a retail generation competitive market." The ACC Chairman then recommended that the ACC establish a new "generic" docket to "determine if changed circumstances require the [ACC] to take another look at electric restructuring in Arizona." Matters that would be addressed by the ACC in the new docket would include:

- whether the ACC should continue implementation of the retail electric competition Rules adopted by the ACC in 1999 in their current form or with modifications;
- whether the ACC should "slow the pace of the implementation of the [Rules] to provide an opportunity to consider the extent to which [Rule] modification and variance is in the public interest, including changing the direction to retail electric competition"; and
- whether the ACC should "step back from electric industry restructuring until the [ACC] is convinced that there exists a viable competitive wholesale electric market to support retail electric competition in Arizona."

On January 22, 2002 the ACC's Chief ALJ issued a procedural order by which a generic docket was opened. On February 8, 2002, the ACC's ALJ issued a procedural order which consolidated the ACC docket relating to APS' October 2001 filing with several other pending ACC dockets, including the generic docket. Although the order consolidates several dockets, it states that a hearing on the APS matter will commence on April 29, 2002. The order went on to state that, contrary to APS' position the ALJ was construing the October 2001 filing as a request by APS to amend the ACC order that approved the 1999 Settlement Agreement.

On March 22, 2002, the ACC Staff issued a report to the ACC recommending that the ACC address the following issues in the generic docket:

- The extent and manner of the ACC's involvement in monitoring market conditions and/or mitigating the development of market power for generation and transmission;
- The lack of guidance in the Rules regarding the mechanics of the "competitive bidding process" referenced above;
- The consideration of alternatives to the transfer of generation assets required by the Rules (the ACC Staff stated that such transfers would be "unwise" at the present time and recommended that "all transfer and separation of utilities' assets be stayed pending the completion of the generic docket");
- The consideration of transmission constraints that could impact the development of the wholesale power market;
- The reassessment of adjustor mechanisms for standard-offer rates in light of problems with the development of a wholesale power market; and
- The adequacy of customer "shopping credits" in the context of the development of a competitive retail market (a shopping credit is the cost a customer does not pay to a utility distribution company if the customer obtains generation from another party).

Although not a specific ACC Staff recommendation, the report was also critical of certain aspects of the proposed purchase power agreement between APS and Pinnacle West.

A modification to the competition Rules or the 1999 Settlement Agreement could, among other things, adversely affect APS' ability to transfer its generation assets to Pinnacle West Energy by December 31, 2002. Pinnacle West cannot predict the outcome of the consolidated docket or its effect on the specific requests in APS' October 2001 filing, the existing Arizona electric competition rules, or the 1999 Settlement Agreement.

Retail Electric Competition Rules. On September 21, 1999, the ACC voted to approve Rules that provide a framework for the introduction of retail electric competition in Arizona. 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 December 8, 1999, APS filed a lawsuit to protect its legal rights regarding the Rules. This lawsuit has been dismissed.

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 APSES, 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 have appealed the ruling to the Arizona Court of Appeals, as a result of which the Superior Court's ruling is automatically stayed pending further judicial review. In a similar appeal concerning the issuance of competitive telecommunications CC&N's, the Arizona Court of Appeals invalidated rates for competitive carriers due to the ACC's failure to establish a fair value rate base for such carriers. That case has been appealed to the Arizona Supreme Court, where a decision is pending.

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 either to an unaffiliated party or to a separate corporate affiliate. 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. APS plans to complete the move of such assets by the end of 2002, as required, although the ACC's recent establishment of a "generic" docket to consider electric industry restructuring in Arizona and the consolidation of that docket with APS' request for approval of a PPA between Pinnacle West and APS could affect APS' ability to transfer assets to Pinnacle West Energy (see "Proposed Rule Variance and Purchase Power Agreement" above).

Provider of Last Resort Obligation. Although the Rules allow retail customers to have access to competitive providers of energy and energy services (see "Retail Electric Competition Rules" below), APS is 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 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, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, 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 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.

1996 Regulatory Agreement. In April 1996, the ACC approved a regulatory agreement between the ACC Staff and APS. Based on the price reduction formula authorized in the agreement, the ACC approved retail price decreases (approximate) as follows (dollars in millions):

ANNUAL ELECTRIC REVENUE DECREASE	PERCENTAGE DECREASE	EFFECTIVE DATE
$49	3.4%	July 1, 1996
$18	1.2%	July 1, 1997
$17	1.1%	July 1, 1998
$11	0.7%	July 1, 1999(a)

(a) Included in the first rate reduction under the 1999 Settlement Agreement (see above).

The regulatory agreement also required that we infuse $200 million of common equity into APS in annual payments of $50 million from 1996 through 1999. All of these equity infusions were made by December 31, 1999.

Legislation. In May 1998, a law was enacted to facilitate implementation of retail electric competition in Arizona. The law includes the following major provisions:

- Arizona's largest government-operated electric utility (Salt River Project) and, at their option, smaller municipal electric systems must (i) make at least 20% of their 1995 retail peak demand available to electric service providers by December 31, 1998 and for all retail customers by December 31, 2000; (ii) decrease rates by at least 10% over a ten-year period beginning as early as January 1, 1991; (iii) implement procedures and public processes comparable to those already applicable to public service corporations for establishing the terms, conditions, and pricing of electric services as well as certain other decisions affecting retail electric competition;
- describes the factors which form the basis of consideration by Salt River Project in determining stranded costs; an
- metering and meter reading services must be provided on a competitive basis during the first two years of competition only for customers having demands in excess of one MW (and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

General

We cannot accurately predict the impact of full retail competition on our financial position, cash flows, results of operations, or liquidity. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete in the new regulatory environment.

Federal

In June 2001, 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 plan remains in effect until September 30, 2002. We cannot accurately predict the overall financial impact of the plan on the various aspects of our business, including our wholesale and purchased power activities.

4. INCOME TAXES

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 the 1999 Settlement Agreement, APS is continuing to accelerate its amortization of the regulatory asset for income taxes over an eight-year period that will end June 30, 2004 (see Note 1). We are including all regulatory asset amortization in depreciation and amortization expense on our consolidated statements of income. The components of income tax expense for continuing operations are:

(dollars in thousands)	year ended December 31, 2001	2000	1999
Current			
Federal	**$ 184,893**	$ 189,779	$ 171,491
State	**45,845**	42,306	37,501
Total Current	**230,738**	232,085	208,992
Deferred	**(16,939)**	(38,625)	(43,886)
ITC amortization	**(264)**	740	(23,514)
Total expense	**$ 213,535**	$ 194,200	$ 141,592

The following chart compares pretax income at the 35% federal income tax rate to income tax expense:

(dollars in thousands)	year ended December 31, 2001	2000	1999
Federal income tax expense at 35% statutory rate	**$ 189,316**	$ 173,786	$ 143,977
Increases (reductions) in tax expense resulting from:			
Preferred stock dividends of APS	**–**	–	356
ITC amortization	**(264)**	740	(23,514)
State income tax net of federal income tax benefit	**23,353**	19,848	19,595
Other	**1,130**	(174)	1,178
Income tax expense	**$ 213,535**	$ 194,200	$ 141,592

The components of the net deferred income tax liability as of December 31, 2001 and 2000 were as follows:

(dollars in thousands)	December 31, 2001	2000
DEFERRED TAX ASSETS		
Deferred gain on Palo Verde Unit 2 sale/leaseback	**$ 25,374**	$ 27,056
Risk management and trading activities	**73,043**	15,002
Other	**110,002**	94,306
Total deferred tax assets	**208,419**	136,364
DEFERRED TAX LIABILITIES		
Plant-related	**1,069,207**	1,081,637
Regulatory asset for income taxes	**121,757**	172,082
Risk management and trading activities	**85,692**	19,892
Total deferred tax liabilities	**1,276,656**	1,273,611
Accumulated deferred income taxes – net	**$ 1,068,237**	$ 1,137,247

Investment Tax Credit

Because of a 1994 rate settlement agreement, we accelerated amortization of substantially all of our ITCs over a five-year period that ended December 31, 1999.

Income Tax Benefit From Discontinued Operations

In 1999, the income tax benefit from discontinued operations for $38 million resulted from resolution of tax issues related to a former subsidiary, MeraBank, A Federal Savings Bank.

5. LINES OF CREDIT

APS had committed lines of credit with various banks of $250 million at December 31, 2001 and 2000, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 2001 and 2000 for these lines of credit were 0.09% per annum. APS had no bank borrowings outstanding under these lines of credit at December 31, 2001 and 2000.

APS' commercial paper borrowings outstanding were $171 million at December 31, 2001 and $82 million at December 31, 2000. The weighted average interest rate on commercial paper borrowings was 4.72% for the year ended December 31, 2001 and 6.64% for the year ended December 31, 2000. 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 with various banks of $250 million at December 31, 2001 and 2000, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commercial paper program was launched in May 2001. The commitment fees ranged from 0.10% to 0.15% in 2001 and 2000. There were no short-term bank borrowings outstanding at December 31, 2001 and $188 million outstanding at December 31, 2000. Pinnacle West commercial paper borrowings were $235 million at December 31, 2001. The weighted average interest rate on commercial paper borrowings was 3.50% for the year ended December 31, 2001.

SunCor had revolving lines of credit totaling $140 million at December 31, 2001 and $120 million at December 31, 2000. The commitment fees were 0.125% in 2001 and 2000. SunCor had $128 million outstanding at December 31, 2001 and $110 million outstanding at December 31, 2000. The balance is included in long-term debt on the consolidated balance sheets (see Note 6).

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 debt is collateralized by interests in certain real property and Pinnacle West's debt is unsecured. The following table presents the components of consolidated long-term debt outstanding at December 31, 2001 and 2000:

(dollars in thousands)	MATURITY DATES (a)	INTEREST RATES	December 31, 2001	2000
APS				
First mortgage bonds	2002	8.125%	**$ 125,000**	$ 125,000
	2004	6.625%	**80,000**	80,000
	2021	9.5%	**–**	45,140
	2021	9.0%	**–**	72,370
	2023	7.25%	**54,150**	70,650
	2024	8.75%	**121,668**	121,668
	2025	8.0%	**33,075**	33,075
	2028	5.5%	**25,000**	25,000
	2028	5.875%	**154,000**	154,000
Unamortized discount and premium			**(5,266)**	(5,993)
Pollution control bonds	2024-2034	Adjustable rate(b)	**386,860**	476,860
Pollution control bonds	2029	3.30%(c)	**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**	–
Floating rate notes	2001	Adjustable rate(d)	**–**	250,000
Senior notes (e)	2006	6.75%	**83,695**	83,695
Capitalized lease obligation	2001-2003	7.75%	**417**	709
Capitalized lease obligation	2006	5.89%	**926**	–
Subtotal			**2,074,525**	2,057,174
SUNCOR				
Revolving credit	2003-2004	(f)	**128,000**	110,000
Notes payable	2001-2008	(g)	**7,912**	8,163
Bonds payable	2024	5.95%	**5,215**	5,215
Bonds payable	2026	6.75%	**7,500**	–
Subtotal			**148,627**	123,378
PINNACLE WEST				
Revolving credit	2001	(h)	**–**	188,000
Senior notes	2003-2006	(i)	**325,000**	50,000
Floating rate notes	2003	Adjustable rate(j)	**250,000**	–
Capitalized lease obligation	2004	7.75%	**1,066**	–
Subtotal			**576,066**	238,000
Total long-term debt			**2,799,218**	2,418,552
Less current maturities			**126,140**	463,469
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			**$2,673,078**	$1,955,083

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.
(b) The weighted-average rate for the year ended December 31, 2001 was 2.55% and for December 31, 2000 was 4.06%. Changes in short-term interest rates would affect the costs associated with this debt.
(c) In November 2001 these bonds were converted to a one year fixed rate of 3.30%. These bonds were previously adjustable rate and from January 1, 2001 until October 31, 2001 the weighted average rate was 2.72%.
(d) The weighted-average rate for the year ended December 31, 2000 was 7.33%. Interest for 2000 was based on LIBOR plus 0.72%.
(e) 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. 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.
(f) The weighted-average rate at December 31, 2001 was 5.31% and at December 31, 2000 was 8.61%. Interest for 2001 and 2000 was based on LIBOR plus 2% or prime plus 0.5%.
(g) Multiple notes primarily with variable interest rates based mostly on the lenders' prime plus 1.75% and lenders' prime plus .25%.
(h) The weighted-average rate at December 31, 2000 was 7.51%. Interest for 2000 was based on LIBOR plus 0.75%.
(i) Includes two series of notes: $25 million at 6.87% due in 2003 and $300 million at 6.4% due in 2006.
(j) The weighted average rate for the year ended December 31, 2001 was 4.65%. Interest for 2001 was based on LIBOR plus 0.98%.

The Pinnacle West and APS bank agreements have financial covenants including an interest coverage test and a debt ratio. We anticipate that we will be able to meet the covenant requirement levels.

The following is a list of principal payments due on total long-term debt and sinking fund requirements through 2006:

- $125 million in 2002;
- $318 million in 2003;
- $507 million in 2004;
- $401 million in 2005; and
- $387 million in 2006.

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. These conditions did not exist at December 31, 2001.

The parent company has issued parental guarantees and obtained surety bonds on behalf of its unregulated subsidiaries, primarily for Pinnacle West Energy's expansion plans and APSES' retail and energy business.

7. RETIREMENT PLANS AND OTHER BENEFITS

Pension Plan

Through 1999, Pinnacle West and its subsidiaries each sponsored defined benefit pension plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single pension plan is sponsored by Pinnacle West for the employees of Pinnacle West and its subsidiaries. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The plan covers nearly all of our employees. Our employees do not contribute to this plan. Generally, we calculate the benefits under this plan based on age, years of service, and pay. We fund the plan by contributing at least the minimum amount required under Internal Revenue Service regulations but no more than the maximum tax-deductible amount. The assets in the plan at December 31, 2001 were mostly domestic and international common stocks and bonds and real estate.

Pension expense, including administrative costs and after consideration of amounts capitalized or billed to electric plant participants, was:

- $7 million in 2001;
- $2 million in 2000; and
- $4 million in 1999.

The following table shows the components of net periodic pension cost before consideration of amounts capitalized or billed to electric plant participants:

(dollars in thousands)	2001	2000	1999
Service cost – benefits earned during the period	$ 26,640	$ 24,955	$ 24,982
Interest cost on projected benefit obligation	62,920	58,361	52,905
Expected return on plan assets	(77,340)	(77,231)	(68,335)
Amortization of:			
Transition asset	(3,227)	(3,227)	(3,226)
Prior service cost	2,716	2,078	2,078
Net actuarial gain	–	(1,633)	–
Net periodic pension cost	$ 11,709	$ 3,303	$ 8,404

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in the consolidated balance sheets:

(dollars in thousands)	2001	2000
Funded status – pension plan assets less than projected benefit obligation	$ (116,213)	$ (20,730)
Unrecognized net transition asset	(13,554)	(16,781)
Unrecognized prior service cost	24,465	18,558
Unrecognized net actuarial (gains)/losses	94,952	(23,816)
Net pension liability recognized in the consolidated balance sheets	$ (10,350)	$ (42,769)

The following table sets forth the defined benefit pension plan's change in projected benefit obligation for the plan years 2001 and 2000:

(dollars in thousands)	2001	2000
Projected pension benefit obligation at beginning of year	$ 795,926	$ 742,638
Service cost	26,640	24,955
Interest cost	62,920	58,361
Benefit payments	(31,647)	(30,568)
Actuarial losses	18,625	540
Plan amendments	8,622	–
Projected pension benefit obligation at end of year	$ 881,086	$ 795,926

The following table sets forth the defined benefit pension plan's change in the fair value of plan assets for the plan years 2001 and 2000:

(dollars in thousands)	2001	2000
Fair value of pension plan assets at beginning of year	$ 775,196	$ 779,913
Actual gain/(loss) on plan assets	(22,876)	1,851
Employer contributions	44,200	24,000
Benefit payments	(31,647)	(30,568)
Fair value of pension plan assets at end of year	$ 764,873	$ 775,196

We made the assumptions below to calculate the pension liability:

	2001	2000
Discount rate	7.50%	7.75%
Rate of increase in compensation levels	4.00%	4.25%
Expected long-term rate of return on assets	10.00%	10.00%

Employee Savings Plan Benefits

Through 1999, Pinnacle West and its subsidiaries each sponsored defined contribution savings plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single defined contribution savings plan is sponsored by Pinnacle West for the employees of Pinnacle West and its subsidiaries. In a defined contribution plan, the benefits a participant will receive result from regular contributions they make to a participant account. Under this plan, we make matching contributions in Pinnacle West stock to participant accounts. At December 31, 2001 approximately 30% of total plan assets were in Pinnacle West stock. We recorded expenses for this plan of approximately $5 million for 2001 and $4 million for 2000 and 1999.

Postretirement Plan

Through 1999, Pinnacle West and its subsidiaries each sponsored postretirement plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single postretirement plan is sponsored by Pinnacle West for the employees of Pinnacle West and its 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 to cover a portion of the plan costs. We retain the right to change or eliminate these benefits.

Funding is based upon actuarially determined contributions that take tax consequences into account. Plan assets consist primarily of domestic stocks and bonds. The postretirement benefit expense after consideration of amounts capitalized or billed to electric plant participants, was:

- $6 million for 2001;
- $3 million for 2000; and
- $7 million for 1999.

The following table shows the components of net periodic postretirement benefit costs before consideration of amounts capitalized or billed to electric plant participants:

(dollars in thousands)	2001	2000	1999
Service cost – benefits earned during the period	$ 9,438	$ 8,613	$ 8,939
Interest cost on accumulated projected benefit obligation	21,585	19,315	17,366
Expected return on plan assets	(21,985)	(22,381)	(18,454)
Amortization of:			
Transition obligation	7,698	7,698	7,698
Net actuarial gains	(4,066)	(7,983)	(5,117)
Net periodic postretirement benefit cost	$ 12,670	$ 5,262	$ 10,432

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in the consolidated balance sheets:

(dollars in thousands)	2001	2000
Funded status – post retirement plan assets less than projected benefit obligation	$ (80,544)	$ (14,851)
Unrecognized net obligation at transition	84,748	92,446
Unrecognized net actuarial gains	(8,606)	(81,280)
Net postretirement amount recognized in the balance sheets	$ (4,402)	$ (3,685)

The following table sets forth the postretirement benefit plan's change in accumulated benefit obligation for the plan years 2001 and 2000:

(dollars in thousands)	2001	2000
Accumulated postretirement benefit obligation at beginning of year	$ 264,006	$ 231,989
Service cost	9,438	8,613
Interest cost	21,585	19,315
Benefit payments	(10,194)	(8,905)
Actuarial losses	33,520	12,994
Accumulated postretirement benefit obligation at end of year	$ 318,355	$ 264,006

The following table sets forth the postretirement benefit plan's change in the fair value of plan assets for the plan years 2001 and 2000:

(dollars in thousands)	2001	2000
Fair value of postretirement plan assets at beginning of year	$ 249,154	$ 257,538
Actual loss on plan assets	(12,550)	(4,436)
Employer contributions	11,400	4,958
Benefit payments	(10,194)	(8,906)
Fair value of postretirement plan assets at end of year	$ 237,810	$ 249,154

We made the assumptions below to calculate the postretirement liability:

	2001	2000
Discount rate	7.50%	7.75%
Expected long-term rate of return on assets – after tax	8.86%	8.77%
Initial health care cost trend rate – under age 65	7.00%	7.00%
Initial health care cost trend rate – age 65 and over	7.00%	6.00%
Ultimate health care cost trend rate	5.00%	5.00%
Year ultimate health care trend rate is reached	2006	2002

The following table shows the effect of a 1% increase or decrease in the health care cost trend rate:

(dollars in millions)	1% INCREASE	1% DECREASE
Effect on 2001 cost of postretirement benefits other than pensions	$ 6	$ (5)
Effect on the accumulated postretirement benefit obligation at December 31, 2001	$ 54	$ (43)

8. 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 of approximately $140 million was deferred and is being amortized to operations 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, an amount equal to the annual lease payments is included in rent expense. A regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis. See Note 2 for a discussion of special purpose entities, including the special purpose entities involved in the Palo Verde sale-leaseback transactions.

The average amounts to be paid for the Palo Verde Unit 2 leases are approximately $49 million per year for the years 2002-2015.

In accordance with the 1999 Settlement Agreement, 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, 2001 was $24 million.

In December 2000, APS purchased Units 1, 2, and 3 of West Phoenix Power Plant, which was previously leased under a capitalized lease obligation.

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

Total lease expense was $56 million in 2001, $58 million in 2000, and $52 million in 1999.

Estimated future minimum lease commitments, are approximately as follows (dollars in millions):

YEAR	
2002	$ 68
2003	66
2004	65
2005	64
2006	63
Thereafter	543
Total future commitments	$ 869

9. 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, 2001. APS' share of operating and maintaining these facilities is included in the income statement in operations and maintenance expense. Each participant is entitled to its share of power generated.

(dollars in thousands)	PERCENT OWNED BY COMPANY	PLANT IN SERVICE	ACCUMULATED DEPRECIATION	CONSTRUCTION WORK IN PROGRESS
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$ 1,822,369	$ (862,880)	$ 10,984
Palo Verde Nuclear Generating Station Unit 2 (see Note 8)	17.0%	571,217	(278,234)	46,284
Four Corners Steam Generating Station Units 4 and 5	15.0%	150,298	(78,983)	503
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	235,409	(104,189)	1,044
Cholla Steam Generating Station				
Common Facilities (a)	62.8%(b)	74,356	(41,555)	1,093
Transmission Facilities:				
ANPP 500KV System	35.8%(b)	67,911	(24,293)	405
Navajo Southern System	31.4%(b)	27,053	(16,833)	202
Palo Verde – Yuma 500KV System	23.9%(b)	9,685	(4,029)	8
Four Corners Switchyards	27.5%(b)	3,071	(1,945)	–
Phoenix – Mead System	17.1%(b)	36,418	(2,766)	–
Palo Verde – Estrella 500KV system	50.0%(b)	–	–	2,215

(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.

10. 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 cancelled.

Power Service Agreement

By letter dated March 7, 2001, Citizens, which owns a utility in Arizona, advised APS that it believes APS has overcharged Citizens by over $50 million under a power service agreement. APS believes that its charges under the agreement were fully in accordance with the terms of the agreement. In addition, in testimony filed with the ACC March 13, 2002, Citizens acknowledged that, based on its review, "if Citizens filed a complaint with 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 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.

SunCor

On March 15, 2001, a jury returned a verdict against SunCor in the amount of $28.6 million, $25.7 million of which represented a punitive damage award, in a lawsuit in Maricopa County, Arizona, Superior Court entitled SunCor Development Company v. Bergstrom Corporation, CV 98-11472. The verdict was based on the Bergstrom Corporation's claims that it was defrauded in connection with the acquisition of approximately ten acres of land in a SunCor commercial development and a subsequent settlement agreement relating to those claims. On December 14, 2001, the Court ruled that the jury award was constitutionally excessive and reduced the punitive damage award to $5 million. Following this ruling, SunCor settled the matter for an amount that did not have a material impact on our 2001 results of operations.

Palo Verde Nuclear Generating Station

Nuclear power plant operators are required to enter into spent fuel disposal contracts with DOE, and 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 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 that it does not intend to begin accepting spent 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 DOE's delay, a number of utilities filed damages actions against DOE in the Court of Federal Claims.

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. A congressional decision on this issue is expected sometime during mid-summer 2002. We cannot currently predict what further steps will be taken in this area.

APS has existing fuel storage pools at Palo Verde and is in the process of completing construction of a new facility for on-site dry storage of spent fuel. With the existing storage pools and the addition of the new facility, APS believes that spent 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 that 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 that it will incur $407 million (in 2001 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, 2001, APS had recorded a liability and regulatory asset of $43 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned to date.

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 $200 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 $88 million, subject to an annual limit of $10 million per incident. Based upon our interest in the three Palo Verde units, our maximum potential assessment per incident for all three units is approximately $77 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.

Fuel and Purchased Power Commitments

APS and Pinnacle West are party to various fuel and purchased power contracts with terms expiring from 2002 through 2021 that include required purchase provisions. We estimate the contract requirements to be approximately $270 million in 2002; $124 million in 2003; $80 million in 2004; $65 million in 2005; and $68 million in 2006. However, this amount may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS estimates its share of the total obligation to be about $103 million. The portion of the coal mine reclamation obligation related to coal already burned is about $59 million at December 31, 2001 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 statements of income.

California Energy Market Issues and Refunds in the Pacific Northwest

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.

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. We have evaluated, among other things, SCE's role as a Palo Verde and Four Corners participant; APS' transactions with the PX and the ISO; contractual relationships with SCE and PG&E; APSES' retail transactions involving SCE and PG&E; and marketing and trading exposures. Based on our evaluations, we have 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 first quarter of 2001. 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 or our subsidiaries or the regional energy market in general.

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. This order calls for a hearing, with findings of fact due to the FERC after the California ISO and PX provide necessary historical data.

The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The ALJ at the FERC in charge of that evidentiary proceeding made an initial finding that no refunds were appropriate. The Pacific Northwest issues will now be addressed by the FERC Commissioners. Although the FERC has not yet made a final ruling in the Pacific Northwest matter or 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 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including Pinnacle West, 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." The complaint indicates that Pinnacle West sold approximately $106 million of power to the California Department of Water Resources from January 17, 2001 to October 31, 2001 and does not allege any amount above "just and reasonable levels." We believe that the claims as they relate to Pinnacle West are without merit.

Construction Program

Consolidated capital expenditures in 2002 are estimated to be:

(dollars in millions)		2002
APS	$	498
Pinnacle West Energy		411
SunCor		79
Other (primarily APSES and Pinnacle West)		35
Total	$	1,023

Generation Expansion

Pinnacle West Energy has completed or announced plans to build about 3,420 MW of natural gas-fired generating capacity from 2000 through 2007 at an estimated cost of about $1.9 billion. This does not reflect an expected reimbursement in 2004 by SNWA of $100 million of Pinnacle West Energy's cumulative capital expenditures in the Silverhawk project in exchange for SNWA purchase of a 25% interest in the project. Our expansion plan will be sized to meet native load growth, cash flow and market conditions. Pinnacle West Energy is currently funding its capital requirements through capital infusions from Pinnacle West, which finances those infusions through debt financings and internally-generated cash. As Pinnacle West Energy develops and obtains additional generation assets, including APS' existing generation assets, Pinnacle West Energy expects to fund its capital requirements through internally-generated cash and its own debt issuances.

Pinnacle West Energy has completed or is currently planning the following projects:

- A 650 MW expansion of the West Phoenix Power Plant in Phoenix. The 120 MW West Phoenix Unit 4 began commercial operation on June 1, 2001. Construction has begun on the 530 MW West Phoenix Unit 5, with commercial operation expected to begin in mid-2003.
- The construction of a four-unit combined cycle 2,120 MW generating station near Palo Verde, called Redhawk. Construction of Units 1 and 2 began in December 2000, and commercial operation is currently scheduled for the summer of 2002. Although Pinnacle West Energy currently plans to bring Units 3 and 4 on line in or before the first quarter of 2007, equipment procurement, engineering and construction plans will allow for these units to come on line as early as 2005 if warranted by market conditions.
- The construction of an 80 MW simple-cycle power plant at Saguaro in Southern Arizona. Commercial operation is currently scheduled for the summer of 2002.
- Development of an electric generating station 20 miles north of Las Vegas, Nevada. Construction of the 570 MW Silverhawk combined-cycle plant is expected to begin in the spring of 2002, with an expected commercial operation date of mid-2004. Pinnacle West Energy has signed a 25% participation agreement with Las Vegas-based SNWA.
- A Pinnacle West Energy affiliate is exploring the possibility of creating an underground natural gas storage facility on Company-owned land west of Phoenix. A feasibility study is in progress to determine if the proposed acreage can support a natural gas storage cavern.

Litigation

We are party to various claims, legal actions, and complaints arising in the ordinary course of business. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial statements or liquidity.

11. NUCLEAR DECOMMISSIONING COSTS

APS recorded $11 million for nuclear decommissioning expense in each of the years 2001, 2000, and 1999. APS estimates it will cost about $1.8 billion ($506 million in 2001 dollars) to decommission its share of the three Palo Verde units. The majority of decommissioning costs are expected to be incurred over a 14-year period beginning in 2024. APS charges decommissioning costs to expense over each unit's operating license term and includes them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

APS' current estimates are based on a 2001 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study. APS is required to update the study every three years.

To fund the costs APS expects to incur to decommission the plant, APS established external decommissioning trusts in accordance with NRC regulations. APS invests the trust funds primarily in fixed income securities and domestic stock and classifies them as available for sale. Realized and unrealized gains and losses are reflected in accumulated depreciation in accordance with industry practice. The following table shows the cost and fair value of our nuclear decommissioning trust fund assets which are reported in investments and other assets on the consolidated balance sheets at December 31, 2001 and 2000:

(dollars in millions)	2001	2000
Trust fund assets – at cost		
Fixed income securities	$ 103	$ 94
Domestic stock	61	52
Total	$ 164	$ 146
Trust fund assets – fair value		
Fixed income securities	$ 106	$ 97
Domestic stock	96	100
Total	$ 202	$ 197

See Note 2 for information on a new accounting standard on accounting for certain liabilities related to closure or removal of long-lived assets.

12. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Consolidated quarterly financial information for 2001 and 2000 is as follows:

(dollars in thousands, except per share amounts)	2001			
QUARTER ENDED	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
Operating revenues (a)				
Electric	$ 906,494	$ 1,261,358	$ 1,531,005	$ 683,608
Real estate	32,335	32,454	43,024	61,095
Operating income	$ 136,063	$ 138,888	$ 298,606	$ 101,070
Income from continuing operations	$ 62,205	$ 66,857	$ 162,499	$ 35,806
Cumulative effect of change in accounting – net of income tax	(2,755)	–	(12,446)	–
Net income	$ 59,450	$ 66,857	$ 150,053	$ 35,806
Earnings (loss) per weighted average common share outstanding – basic				
Continuing operations – basic	$ 0.73	$ 0.79	$ 1.92	$ 0.42
Cumulative effect of change in accounting – basic	$ (0.03)	$ –	$ (0.15)	$ –
Earnings per weighted average common share outstanding – basic	$ 0.70	$ 0.79	$ 1.77	$ 0.42
Earnings (loss) per weighted average common share outstanding – diluted				
Continuing operations – diluted	$ 0.73	$ 0.79	$ 1.91	$ 0.42
Cumulative effect of change in accounting – diluted	(0.03)	–	(0.14)	–
Earnings per weighted average common share outstanding – diluted	$ 0.70	$ 0.79	$ 1.77	$ 0.42
Dividends declared per share	$ 0.375	$ 0.375	$ 0.375	$ 0.40

(dollars in thousands, except per share amounts)

QUARTER ENDED	2000 MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
Operating revenues (a)				
Electric	$ 446,228	$ 720,174	$ 1,567,960	$ 797,448
Real estate	41,889	36,374	39,396	40,706
Operating income	$ 91,565	$ 190,942	$ 241,264	$ 117,976
Net income	$ 54,070	$ 89,901	$ 116,049	$ 42,312
Earnings per weighted average common share outstanding				
Net income – basic	$ 0.64	$ 1.06	$ 1.37	$ 0.50
Net income – diluted	$ 0.64	$ 1.06	$ 1.37	$ 0.50
Dividends declared per share	$ 0.35	$ 0.35	$ 0.35	$ 0.375

(a) Electric revenues are seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 2001 and 2000 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 2001 and 2000 fair values of such investments, which we determine by using quoted market values, approximate their carrying amount.

On December 31, 2001, the carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.80 billion, with an estimated fair value of $2.82 billion. The carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.42 billion on December 31, 2000, with an estimated fair value of $2.48 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

14. EARNINGS PER SHARE

The following table presents earnings per weighted average common share outstanding (EPS):

	2001	2000	1999
Basic EPS:			
Continuing operations	$ 3.86	$ 3.57	$ 3.18
Discontinued operations	–	–	0.45
Extraordinary charge	–	–	(1.65)
Cumulative effect of change in accounting	(0.18)	–	–
Earnings per share – basic	$ 3.68	$ 3.57	$ 1.98
Diluted EPS:			
Continuing operations	$ 3.85	$ 3.56	$ 3.17
Discontinued operations	–	–	0.45
Extraordinary charge	–	–	(1.65)
Cumulative effect of change in accounting	(0.17)	–	–
Earnings per share – diluted	$ 3.68	$ 3.56	$ 1.97

Dilutive stock options increased average common shares outstanding by 212,491 shares in 2001, 202,738 shares in 2000, and 291,392 shares in 1999. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 84,930,140 shares in 2001, 84,935,282 shares in 2000, and 85,008,527 shares in 1999.

Options to purchase 212,562 shares of common stock were outstanding at December 31, 2001 but were not included in the computation of diluted EPS 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 EPS were 517,614 at December 31, 2000 and 506,734 at December 31, 1999.

15. STOCK-BASED COMPENSATION

Pinnacle West offers two stock incentive plans for officers and key employees of our company and our subsidiaries.

One of the plans (1994 plan) provides for the granting of new options (which may be non-qualified stock options or incentive stock options) of up to 3.5 million shares at a price per option not less than the fair market value on the date the option is granted. The other plan (1985 plan) includes outstanding options but no new options will be granted from this 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 plan also provides for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

The awards outstanding under the incentive plans at December 31, 2001, are 1,832,725 non-qualified stock options, 237,833 shares of restricted stock, and no incentive stock options, stock appreciation rights or dividend equivalents.

SFAS No. 123, "Accounting for Stock-Based Compensation" encourages, but does not require, that a company record compensation expense based on the fair value of options granted (the fair value method). We continue to recognize expense based on Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."

If we had recorded compensation expense based on the fair value method, our net income and earnings per share would have been reduced to the following pro forma amounts:

(dollars in thousands)	2001	2000	1999
Net income			
As reported	$312,166	$302,332	$167,887
Pro forma (fair value method)	$309,800	$301,102	$166,913
Earnings per share – basic			
As reported	$ 3.68	$ 3.57	$ 1.98
Pro forma (fair value method)	$ 3.66	$ 3.55	$ 1.97

In order to present 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:

	2001	2000	1999
Risk-free interest rate	4.08%	5.81%	5.68%
Dividend yield	3.70%	3.48%	3.33%
Volatility	27.66%	32.00%	20.50%
Expected life (months)	60	60	60

The following table is a summary of the status of our stock option plans as of December 31, 2001, 2000, and 1999 and changes during the years ending on those dates:

(dollars in thousands)	2001 SHARES	2001 WEIGHTED AVERAGE EXERCISE PRICE	2000 SHARES	2000 WEIGHTED AVERAGE EXERCISE PRICE	1999 SHARES	1999 WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at beginning of year	1,569,171	$ 37.55	1,441,124	$ 33.45	1,563,512	$ 27.95
Granted	444,200	42.55	451,450	43.28	458,450	35.95
Exercised	(162,229)	28.53	(283,819)	20.90	(516,838)	18.19
Forfeited	(18,417)	41.67	(39,584)	39.86	(64,000)	40.36
Outstanding at end of year	1,832,725	39.52	1,569,171	37.55	1,441,124	33.45
Options exercisable at year-end	926,315	37.41	831,537	34.37	835,381	29.69
Weighted average fair value of options granted during the year		8.84		11.81		7.05

The following table summarizes information about our stock option plans at December 31, 2001:

EXERCISE PRICES PER SHARE	OPTIONS OUTSTANDING	WEIGHTED-AVERAGE EXERCISE PRICE	WEIGHTED AVERAGE REMAINING CONTRACT LIFE (YEARS)	OPTIONS EXERCISABLE	WEIGHTED-AVERAGE EXERCISE PRICE
$14.03-18.71	15,150	$ 18.09	0.5	15,150	$ 18.09
18.71-23.39	88,284	20.53	2.3	88,284	20.53
23.39-28.07	78,167	27.39	4.6	64,834	27.44
28.07-32.75	72,250	31.44	4.8	72,250	31.44
32.75-37.42	285,024	34.69	7.7	165,245	34.69
37.42-42.10	217,500	40.15	6.1	175,500	39.95
42.10-46.78	1,076,350	43.96	8.8	345,052	45.70
	1,832,725			926,315	

16. BUSINESS SEGMENTS

We have two principal business segments (determined by products, services and regulatory environment), which consist of regulated retail electricity business and related activities (retail business segment) and competitive business activities (marketing and trading segment). Our retail business segment currently includes activities related to electricity transmission and distribution, as well as electricity generation. Our marketing and trading business segment currently includes activities related to wholesale marketing and trading and APSES' competitive energy services.

These reportable segments reflect a change in the reporting of our segment information. Before the fourth quarter of 2001, we had two segments (generation and delivery). The "generation segment" information combined our marketing and trading activities with our generation of electricity activities. The "delivery segment" included transmission and distribution activities.

In the fourth quarter of 2001, APS filed with the ACC a proposed rule variance and purchase power agreement with the ACC (see Note 3) that inherently views our business in the new reportable segments described above. Internal management reporting has been changed to reflect this alignment. The corresponding information for earlier periods has been restated. The other amounts include activity relating to the parent company and other subsidiaries including SunCor and El Dorado. Financial data for the business segments is provided as follows:

BUSINESS SEGMENTS FOR THE YEAR ENDED DECEMBER 31, 2001

(dollars in millions)	RETAIL	MARKETING AND TRADING	OTHER	TOTAL
Operating revenues	$ 2,562	$ 1,820	$ 169	$ 4,551
Purchased power and fuel costs	1,161	1,503	–	2,664
Other operating expenses	602	32	156	790
Operating margin	799	285	13	1,097
Depreciation and amortization	423	1	4	428
Interest and other expenses	124	–	4	128
Pretax margin	252	284	5	541
Income taxes	100	112	2	214
Income from continuing operations	152	172	3	327
Cumulative effect of change in accounting for derivatives – net of income taxes of $10	(15)	–	–	(15)
Net income	$ 137	$ 172	$ 3	$ 312
Total assets	$ 6,938	$ 556	$ 488	$ 7,982
Capital expenditures	$ 1,004	$ 23	$ 102	$ 1,129

BUSINESS SEGMENTS FOR THE YEAR ENDED DECEMBER 31, 2000

(dollars in millions)	RETAIL	MARKETING AND TRADING	OTHER	TOTAL
Operating revenues	$ 2,539	$ 993	$ 158	$ 3,690
Purchased power and fuel costs	1,066	867	–	1,933
Other operating expenses	538	21	126	685
Operating margin	935	105	32	1,072
Depreciation and amortization	425	1	5	431
Interest and other expenses	141	–	4	145
Pretax margin	369	104	23	496
Income taxes	144	41	9	194
Net income	$ 225	$ 63	$ 14	$ 302
Total assets	$ 6,326	$ 386	$ 451	$ 7,163
Capital expenditures	$ 665	$ –	$ 50	$ 715

BUSINESS SEGMENTS FOR THE YEAR ENDED DECEMBER 31, 1999

(dollars in millions)	RETAIL	MARKETING AND TRADING	OTHER	TOTAL
Operating revenues	$ 1,916	$ 377	$ 130	$ 2,423
Purchased power and fuel costs	433	360	–	793
Other operating expenses	549	9	95	653
Operating margin	934	8	35	977
Depreciation and amortization	417	–	3	420
Interest and other expenses	142	–	3	145
Pretax margin	375	8	29	412
Income taxes	129	3	10	142
Income from continuing operations	246	5	19	270
Income tax benefit from discontinued operations	38	–	–	38
Extraordinary charge – net of income taxes of $94	(140)	–	–	(140)
Net income	$ 144	$ 5	$ 19	$ 168
Capital expenditures	$ 353	$ –	$ 126	$ 479

17. DERIVATIVE INSTRUMENTS

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions 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 commodity. In addition, subject to specified risk parameters established by the Board of Directors and monitored by the Energy Risk Management Committee, we engage in trading activities intended to profit from market price movements.

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including one counterparty for which a worst case exposure represents approximately 50% of our $267 million of risk management and trading assets as of December 31, 2001. We use a risk management process to assess and monitor the financial exposure of this 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 counterparty 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. Credit reserves are established representing our estimated credit losses on our overall exposure to counterparties. See Note 1 for a discussion of our credit reserve policy.

Effective January 1, 2001, we adopted 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 sheets and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in income or shareholders' equity (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. Hedge effectiveness is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in the fair value resulting from ineffectiveness is recognized immediately in net income. This new standard may result in additional volatility in our net income and comprehensive income.

As a result of adopting SFAS No. 133, we recognized $118 million of derivative assets and $16 million of derivative liabilities in our consolidated balance sheets as of January 1, 2001. Also as of January 1, 2001, we recorded a $3 million after-tax loss in net income and a $64 million after-tax gain in equity (as a component of other comprehensive income) both as a cumulative effect of a change in accounting principle. The gain resulted from unrealized gains on cash flow hedges.

In June 2001, the FASB issued new guidance related to electricity contracts. The effective date of this new guidance was July 1, 2001. As of July 1, 2001, we recorded an additional $12 million after-tax loss in net income and an additional $8 million after-tax gain in equity (as a component of other comprehensive income), as a result of adopting the new guidance related to electricity contracts. The loss resulted primarily from electricity options contracts. The gain resulted from unrealized gains on cash flow hedges. The impact of the new guidance is reflected in net income and other comprehensive income as a cumulative effect of change in accounting principle.

In December 2001, the FASB issued revised guidance on the accounting for electricity contracts with option characteristics and the accounting for contracts that combine a forward contract and a purchased option contract. The effective date for the revised guidance is April 1, 2002. We are currently evaluating the new guidance to determine what impact, if any, it will have on our financial statements.

The change in derivative fair value included in the consolidated statements of income for the year ending December 31, 2001 is comprised of the following:

(dollars in thousands)	December 31, 2001
Ineffective portion of derivatives qualifying for hedge accounting (a)	$ (8,371)
Discontinuance of cash flow hedges for forecasted transactions that will not occur	(9,525)
Reclassification of mark-to-market losses to realized	25,948
Total	$ 8,052

(a) Time value component of options excluded from assessment of hedge effectiveness.

As of December 31, 2001, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions is thirty-six months. During the twelve months ended December 31, 2002, we estimate that a net loss of $23 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 transaction.

The following table summarizes our assets and liabilities from risk management and trading activities related to trading and system (retail and traditional wholesale activities) as of December 31, 2001 and 2000 (dollars in thousands):

December 31, 2001	CURRENT ASSETS	INVESTMENTS	CURRENT LIABILITIES	OTHER LIABILITIES	NET ASSET(LIABILITY)
Mark-to-market:					
Trading	$ 56,876	$ 148,457	$ (14,154)	$ (53,253)	$ 137,926
System	10,097	–	(21,840)	(95,159)	(106,902)
Trading – at cost	–	51,894	–	(59,164)	(7,270)
Total	$ 66,973	$ 200,351	$ (35,994)	$ (207,576)	$ 23,754

December 31, 2000	CURRENT ASSETS	INVESTMENTS	CURRENT LIABILITIES	OTHER LIABILITIES	NET ASSET (LIABILITY)
Trading – mark-to-market	$ 17,506	$ 32,955	$ (37,179)	$ (877)	$ 12,405
Trading – at cost	–	–	–	(13,834)	(13,834)
Total	$ 17,506	$ 32,955	$ (37,179)	$ (14,711)	$ (1,429)

Net gains and losses on instruments utilized for trading activities are recognized in marketing and trading revenues on a current basis (the mark-to-market method). Trading positions are measured at fair value as of the balance sheet date. The unrealized trading gains recognized in marketing and trading revenues were $127 million for the year ended December 31, 2001 and $14 million for the year ended December 31, 2000.

18. SUBSEQUENT EVENTS

On February 8, 2002, Pinnacle West issued $215 million of 4.5% Notes due 2004. On March 1, 2002, APS issued $375 million of 6.50% Notes due 2012. On March 15, 2002, APS announced the redemption on April 15, 2002 of approximately $125 million of its First Mortgage Bonds, 8.75% series during 2024.

On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including Pinnacle West, failed to properly file rate information at the FERC in connection with sales to California from 2000 to 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." The complaint indicates that Pinnacle West sold approximately $106 million of power to California Department of Water Resources from January 17, 2001 to October 31, 2001 and does not allege any amount above "just and reasonable levels." We believe that the claims as they relate to Pinnacle West are without merit.

See Note 3 for information relating to the March 22, 2002 ACC Staff report addressing issues in the generic docket.

BOARD OF DIRECTORS

PAMELA GRANT
(63) 1980*
Civic Leader
Committees:
Human Resources, Chairman
Audit

MARTHA O. HESSE
(59) 1991
President, Hesse Gas Company
Committees:
Audit, Chairman
Finance and Operating

THE REV. BILL JAMIESON, JR.
(58) 1991
President, Institute for Servant Leadership of Asheville, North Carolina
Committee:
Human Resources

ROY A. HERBERGER, JR.
(59) 1992
President, Thunderbird, The American Graduate School of International Management
Committees:
Finance and Operating, Chairman
Human Resources

ROBERT G. MATLOCK
(68) 1993
Management Consultant
R.G. Matlock & Associates, Inc.
Committee:
Human Resources

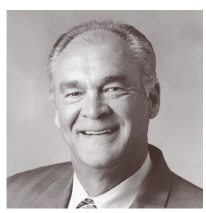
WILLIAM J. POST
(51) 1994
Chairman of the Board & Chief Executive Officer
Committee:
Finance and Operating

HUMBERTO S. LOPEZ
(56) 1995
President, HSL Properties, Inc.
Committee:
Audit

MICHAEL L. GALLAGHER
(57) 1997
Chairman Emeritus
Gallagher & Kennedy, P.A.
Committee:
Human Resources

BRUCE J. NORDSTROM
(52) 1997
Certified Public Accountant,
Nordstrom and Associates, P.C.
Committee:
Audit

JACK E. DAVIS
(55) 1998
President
Committee:
Finance and Operating



WILLIAM L. STEWART
(58) 1998
President, Pinnacle West Energy

EDDIE BASHA
(64) 1999
Chairman of the Board, Bashas'
Committee:
Audit

KATHRYN L. MUNRO
(53) 1999
Chairman, BridgeWest L.L.C.
Committee:
Finance and Operating

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

OFFICERS

PINNACLE WEST

William J. Post
(51) 1973*
Chairman of the Board &
Chief Executive Officer

Jack E. Davis
(55) 1973
President

Armando B. Flores
(58) 1991
Executive Vice President,
Corporate Business Services

Steven M. Wheeler
(53) 2001
Senior Vice President,
Transmission, Regulation & Planning

Robert S. Aiken
(45) 1986
Vice President, Federal Affairs

John G. Bohon
(56) 1971
Vice President, Corporate Services &
Human Resources

Dennis L. Brown
(51) 1973
Vice President &
Chief Information Officer

Edward Z. Fox
(48) 1995
Vice President, Communications,
Environment & Safety

Chris N. Froggatt
(44) 1986
Vice President & Controller

David A. Hansen
(42) 1980
Vice President, Bulk Power
Marketing & Trading

Nancy C. Loftin
(48) 1985
Vice President & General Counsel

Michael V. Palmeri
(43) 1982
Vice President, Finance

Donald G. Robinson
(48) 1978
Vice President,
Regulation & Planning

Martin L. Shultz
(57) 1979
Vice President, Government Affairs

Faye Widenmann
(53) 1978
Vice President & Secretary

Barbara M. Gomez
(47) 1978
Treasurer

ARIZONA PUBLIC SERVICE

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

Jack E. Davis
President,
Energy Delivery & Sales

William L. Stewart
(58) 1994
President, Generation

Steven M. Wheeler
Senior Vice President
Transmission, Regulation & Planning

Michael V. Palmeri
Vice President, Finance

Faye Widenmann
Vice President & Secretary

Nancy C. Loftin
Vice President & General Counsel

Barbara M. Gomez
Treasurer

Jan H. Bennett
(54) 1967
Vice President, Customer Service

James M. Levine
(52) 1989
Executive Vice President,
Generation

Gregg R. Overbeck
(55) 1990
Senior Vice President,
Nuclear Generation

John R. Denman
(59) 1964
Vice President, Fossil Generation

William E. Ide
(55) 1977
Vice President,
Nuclear Production

David Mauldin
(52) 1990
Vice President, Nuclear
Engineering & Support

PINNACLE WEST ENERGY

William L. Stewart
President

James M. Levine
Chief Operating Officer

Ajoy K. Banerjee
(56) 1999
Vice President, Generation Expansion

Ajit P. Bhatti
(56) 1973
Vice President, Generation Planning

Warren C. Kotzmann
(52) 1989
Vice President, Business &
Corporate Services

APS ENERGY SERVICES

Vicki G. Sandler
(45) 1982
President, Energy Services

SUNCOR DEVELOPMENT

William J. Post
Chairman of the Board

John C. Ogden
(56) 1972
President & Chief Executive Officer

Geoffrey L. Appleyard
(48) 1987
Vice President & Chief Financial Officer

Duane S. Black
(49) 1989
Vice President & Chief Operating Officer

Jay T. Ellingson
(52) 1992
Vice President, Development –
Palm Valley

Steven Gervais
(46) 1987
Vice President & General Counsel

Margaret E. Kirch
(52) 1988
Vice President,
Commercial Development

Thomas A. Patrick
(48) 1995
Vice President, Golf Operations

EL DORADO INVESTMENT

William J. Post
Chairman of the Board,
President & CEO

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

SHAREHOLDER INFORMATION

CORPORATE HEADQUARTERS

400 North 5th Street
P.O. Box 53999
Phoenix, Arizona 85004

Main telephone number: (602) 250-1000

ANNUAL MEETING OF SHAREHOLDERS

Wednesday, May 22, 2002
10:30 a.m.
The Herberger Theatre
222 East Monroe Street
Phoenix, Arizona 85004

STOCK LISTING

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

FORM 10-K

Pinnacle West's Annual Report to the Securities and Exchange Commission on Form 10-K will be available after April 1, 2002 to shareholders upon written request, without charge. Write: Office of the Secretary.

INVESTORS ADVANTAGE PLAN

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

Pinnacle West Capital Corporation
Shareholder Department
P.O. Box 52133
Phoenix, AZ 85072-2133

CORPORATE WEB SITE

www.pinnaclewest.com

TRANSFER AGENTS AND REGISTRAR

Common Stock
Pinnacle West Capital Corporation
Stock Transfer Department
P.O. Box 52134
Phoenix, Arizona 85072-2134
Or:
After January 1, 2003,
400 North 5th Street
Phoenix, Arizona 85004
Telephone: (602) 250-5506

SHAREHOLDER ACCOUNT AND ADMINISTRATIVE INFORMATION

Shareholder Department telephone number (toll-free):
(800) 457-2983

STATISTICAL REPORT

A detailed Statistical Report for Financial Analysis for 1996-2001 will be available in April on the Company's Web site or by writing to the Investor Relations Department.

INVESTOR RELATIONS CONTACT

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

STATEWIDE ASSOCIATION FOR UTILITY INVESTORS

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

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

ENVIRONMENTAL, HEALTH AND SAFETY REPORT

To view the *APS Environmental, Health and Safety Report* please visit www.aps.com, or to receive a printed summary report, call (602) 250-3282.

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

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