UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Year Ended December 31, 2002
Commission File No. 1-8968

ANADARKO PETROLEUM CORPORATION

1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046
(832) 636-1000

Incorporated in the State of Delaware **Employer Identification No. 76-0146568**

Securities registered pursuant to Section 12(b) of the Act:

Common Stock, par value $0.10 per share
Preferred Stock Purchase Rights

The above Securities are listed on the New York Stock Exchange.

Securities registered Pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ✓ No ____.

Indicate by check mark if the disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K ____.

Indicate by check mark whether registrant is an accelerated filer. Yes ✓ No ____.

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 28, 2002 was $12,128,594,000.

The number of shares outstanding of the Company's common stock as of February 28, 2003 is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value $0.10 per share	248,925,066

Part of Form 10-K	Documents Incorporated By Reference
Part II	Portions of the Anadarko Petroleum Corporation 2002 Annual Report to Stockholders.
Part III	Portions of the Proxy Statement, dated March 24, 2003, for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held April 24, 2003.

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PART I

Item 1. Business

General

Anadarko Petroleum Corporation is among the largest independent oil and gas exploration and production companies in the world, with 2.3 billion barrels of oil equivalent (BOE) of proved reserves as of December 31, 2002. The Company's major areas of operations are located in the United States, primarily in Texas, Louisiana, the mid-continent region and the western states, Alaska and in the shallow and deep waters of the Gulf of Mexico, as well as in Canada and Algeria. The Company is also active in Venezuela, Qatar, Oman, Egypt, Australia, Tunisia and Gabon. The Company actively markets natural gas, oil and natural gas liquids (NGLs) production and owns and operates gas gathering systems in its core producing areas. In addition, the Company engages in the hard minerals business through non-operated joint ventures and royalty arrangements in several coal, trona (natural soda ash) and industrial mineral mines located on lands within and adjacent to its Land Grant holdings. The Land Grant is an 8 million acre strip running through portions of Colorado, Wyoming and Utah where the Company owns most of its fee mineral rights.

In July 2000, the Company merged with Union Pacific Resources Group Inc., subsequently renamed Anadarko Holding Company (Anadarko Holding). The merger was a tax-free reorganization and accounted for as a purchase business combination. As such, the financial and operating results and property descriptions presented here, unless expressly noted otherwise, are those of Anadarko on a stand-alone basis for the periods up to the merger and of the combined Company from that date forward.

Unless the context otherwise requires, the terms *"Anadarko"* or *"Company"* refer to Anadarko and its subsidiaries. The Company's corporate headquarters are located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380, where the telephone number is (832) 636-1000.

Available Information The Company files Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, registration statements and other items with the Securities and Exchange Commission (SEC). Anadarko provides access free of charge to all of these SEC filings, as soon as reasonably practicable after filing, on its Internet site located at www.anadarko.com. The Company will also make available to any stockholder, without charge, copies of its Annual Report on Form 10-K as filed with the SEC. For copies of this, or any other filings, please contact: Anadarko Petroleum Corporation, Public Affairs Department, P.O. Box 1330, Houston, Texas 77251-1330 or call (832) 636-3498.

In addition, the public may read and copy any materials Anadarko files with the SEC at the SEC's Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers, like Anadarko, that file electronically with the SEC.

Oil and Gas Properties and Activities

Proved Reserves and Future Net Cash Flows

As of December 31, 2002, Anadarko had proved reserves of 1.1 billion barrels of crude oil, condensate and NGLs and 7.2 trillion cubic feet (Tcf) of natural gas. Combined, these proved reserves are equivalent to 2.3 billion barrels of oil or 14.0 Tcf of gas. The Company's reserves have grown significantly over the past three years due to: the Anadarko Holding merger transaction in 2000; the acquisitions of Berkley Petroleum Corp. (Berkley) and Gulfstream Resources Canada Limited (Gulfstream) in 2001 and Howell Corporation (Howell) in 2002; substantial natural gas reserves discovered in the Gulf of Mexico, Canada and onshore in the U.S.; crude oil reserves added in Algeria and Alaska; and, through other acquisitions of producing properties.

As of December 31, 2002, Anadarko had proved developed reserves of 5.3 Tcf of natural gas and 686 million barrels (MMBbls) of crude oil, condensate and NGLs. Proved developed reserves comprise 67% of total proved reserves.

The Company's estimates of proved reserves and proved developed reserves at December 31, 2002, 2001 and 2000 and changes in proved reserves during the last three years are contained in the *Supplemental*

Information on Oil and Gas Exploration and Production Activities — Unaudited (Supplemental Information) in the Anadarko Petroleum Corporation 2002 Consolidated Financial Statements (Consolidated Financial Statements) under Item 8 of this Form 10-K Annual Report (Form 10-K). The Company files annual estimates of certain proved oil and gas reserves with the U.S. Department of Energy, which are within 5% of the amounts included in the above estimates. See *Critical Accounting Policies* under Item 7 of this Form 10-K.

Also contained in the *Supplemental Information* in the Consolidated Financial Statements are the Company's estimates of future net cash flows, discounted future net cash flows before income taxes and discounted future net cash flows after income taxes from proved reserves.

Sales Volumes and Prices

The following table shows the Company's annual sales volumes. Volumes for natural gas are in billion cubic feet (Bcf) at a pressure base of 14.73 pounds per square inch and volumes for oil, condensate and NGLs are in MMBbls. Total volumes are in million barrels of oil equivalent (MMBOE). For this computation, six thousand cubic feet (Mcf) of gas is the energy equivalent of one barrel of oil, condensate or NGLs.

	2002	2001	2000
United States			
Natural gas (Bcf)	**507**	573	338
Oil and condensate (MMBbls)	**31**	34	15
Natural gas liquids (MMBbls)	**14**	14	12
Total (MMBOE)	**130**	144	83
Canada			
Natural gas (Bcf)	**135**	121	46
Oil and condensate (MMBbls)	**12**	13	4
Natural gas liquids (MMBbls)	**1**	1	—
Total (MMBOE)	**35**	34	12
Algeria			
Oil and condensate (MMBbls)	**24**	8	10
Total (MMBOE)	**24**	8	10
Other International			
Natural gas (Bcf)	**—**	1	1
Oil and condensate (MMBbls)	**8**	13	7
Total (MMBOE)	**8**	13	7
Total			
Natural gas (Bcf)	**642**	695	385
Oil and condensate (MMBbls)	**75**	68	36
Natural gas liquids (MMBbls)	**15**	15	12
Total (MMBOE)	**197**	199	112

The following table shows the Company's annual average sales prices and average production costs. The average sales prices include realized gains and losses for derivative contracts the Company enters to manage price risk related to the Company's sales volumes. Production costs are costs incurred to operate and maintain the Company's wells and related equipment and include cost of labor, well service and repair, location maintenance, power and fuel, property taxes, production and severance taxes and overhead charges. Certain amounts for prior years have been reclassified to conform to the current presentation. Additional information on volumes, prices and markets is contained in *Financial Results* and *Marketing Strategies* under Item 7 of this Form 10-K. Information on major customers is contained in *Note 12* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

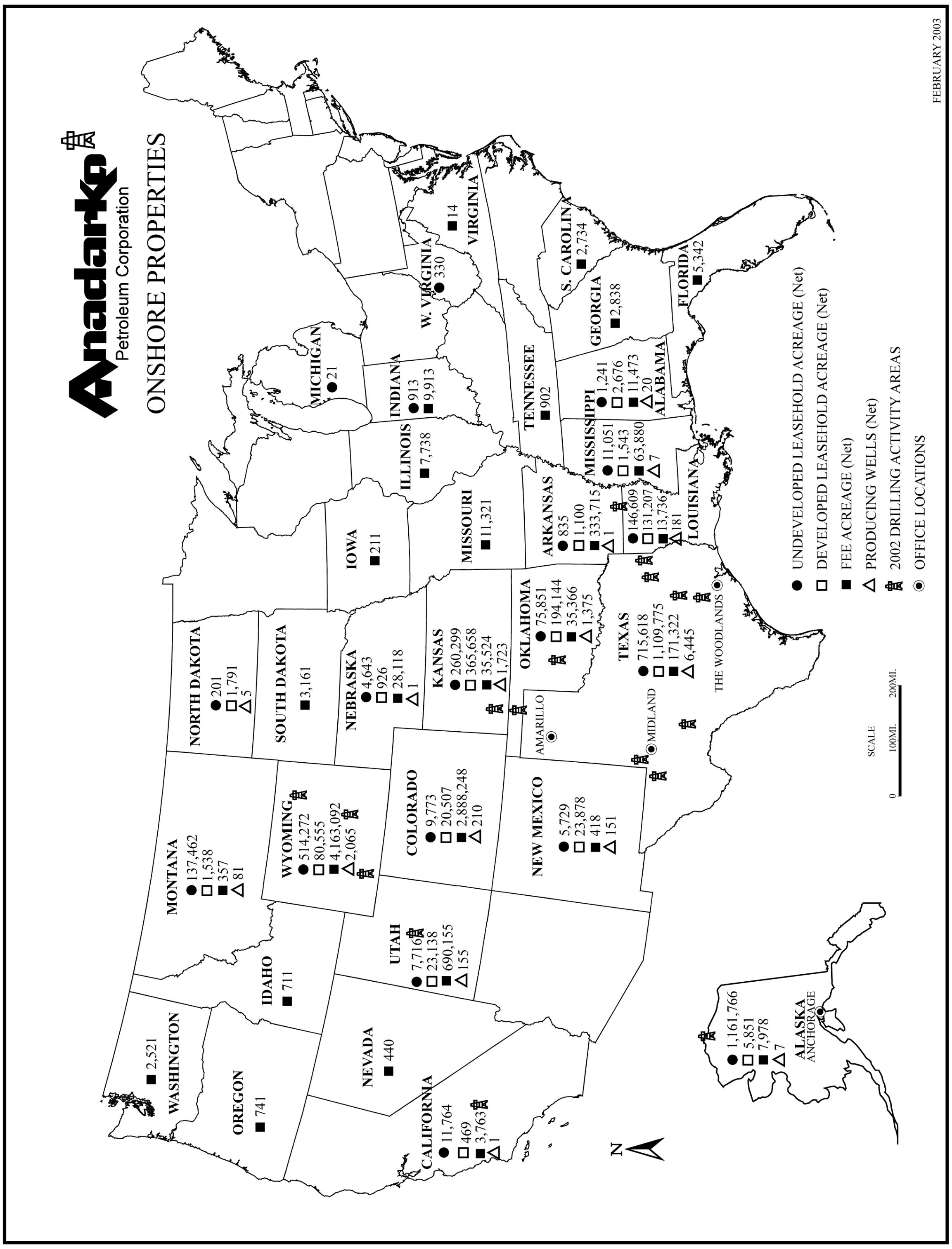
	2002	2001	2000
United States			
Sales price			
Natural gas (per Mcf)	**$ 2.84**	$ 4.23	$ 4.22
Oil and condensate (per barrel)	**23.07**	23.08	28.59
Natural gas liquids (per barrel)	**14.98**	16.44	21.65
Production cost (per BOE)	**$ 4.66**	$ 4.66	$ 5.05
Canada			
Sales price			
Natural gas (per Mcf)	**$ 2.93**	$ 4.38	$ 4.09
Oil and condensate (per barrel)	**19.31**	18.18	27.33
Natural gas liquids (per barrel)	**12.11**	18.32	—
Production cost (per BOE)	**$ 6.40**	$ 5.97	$ 6.80
Algeria			
Sales price			
Oil and condensate (per barrel)	**$24.38**	$23.97	$28.73
Production cost (per BOE)	**$ 1.78**	$ 2.33	$ 2.61
Other International			
Sales price			
Natural gas (per Mcf)	**$ —**	$ 1.22	$ 1.08
Oil and condensate (per barrel)	**19.92**	14.35	18.35
Production cost (per BOE)	**$ 8.48**	$ 5.71	$ 8.24
Total			
Sales price			
Natural gas (per Mcf)	**$ 2.86**	$ 4.25	$ 4.19
Oil and condensate (per barrel)	**22.55**	20.56	26.42
Natural gas liquids (per barrel)	**14.80**	16.55	21.70
Production cost (per BOE)	**$ 4.79**	$ 4.85	$ 5.27

Properties and Activities — United States

Reserves in the United States comprised 66% of Anadarko's total proved reserves at year-end 2002 compared to 61% in 2001 and 64% in 2000. During 2002, drilling results included 392 gas wells, 98 oil wells and 24 dry holes. The accompanying maps illustrate by state Anadarko's undeveloped and developed lease and fee acreage, number of net producing wells and other data relevant to its domestic onshore and offshore oil and gas operations.

Onshore — Lower 48 States

Overview About 54% of the Company's proved reserves are located onshore in the Lower 48 states, with operations primarily in Texas, Louisiana, the mid-continent region and western states. In 2002, average production from the Company's onshore properties was 1,165 million cubic feet per day (MMcf/d) of gas and 91 thousand barrels per day (MBbls/d) of crude oil, condensate and NGLs, or 53% of the Company's total production volumes. Anadarko has 2,642,000 gross (1,904,000 net) undeveloped lease acres, 2,900,000 gross (1,959,000 net) developed lease acres and 9,538,000 gross (8,488,000 net) fee acres onshore in the Lower 48 states.



Anadarko Petroleum Corporation
ONSHORE PROPERTIES
WASHINGTON ■ 2,521
OREGON ■ 741
IDAHO ■ 711
MONTANA ● 137,462 □ 1,538 ■ 357 △ 81
NORTH DAKOTA ● 201 □ 1,791 △ 5
SOUTH DAKOTA ■ 3,161
WYOMING ● 514,272 □ 80,555 ■ 4,163,092 △ 2,065
NEBRASKA ● 4,643 □ 926 ■ 28,118 △ 1
IOWA ■ 211
MICHIGAN ● 21
NEVADA ■ 440
UTAH ● 7,716 □ 23,138 ■ 690,155 △ 155
COLORADO ● 9,773 □ 20,507 ■ 2,888,248 △ 210
KANSAS ● 260,299 □ 365,658 ■ 35,524 △ 1,723
ILLINOIS ■ 7,738
INDIANA ● 913 ■ 9,913
W. VIRGINIA ● 330
VIRGINIA ■ 14
CALIFORNIA ● 11,764 □ 469 ■ 3,763 △ 1
MISSOURI ■ 11,321
NEW MEXICO ● 5,729 □ 23,878 ■ 418 △ 151
AMARILLO
OKLAHOMA ● 75,851 □ 194,144 ■ 35,366 △ 1,375
ARKANSAS ● 835 □ 1,100 ■ 333,715 △ 1
TENNESSEE ■ 902
MISSISSIPPI ● 11,051 □ 1,543 ■ 63,880 △ 7
ALABAMA ● 1,241 □ 2,676 ■ 11,473 △ 20
GEORGIA ■ 2,838
S. CAROLINA ■ 2,734
FLORIDA ■ 5,342
TEXAS ● 715,618 □ 1,109,775 ■ 171,322 △ 6,445
MIDLAND
LOUISIANA ● 146,609 □ 131,207 ■ 13,736 △ 181
THE WOODLANDS
ALASKA ● 1,161,766 □ 5,851 ■ 7,978 △ 7
ANCHORAGE
N
SCALE
0 100MI. 200MI.
● UNDEVELOPED LEASEHOLD ACREAGE (Net)
□ DEVELOPED LEASEHOLD ACREAGE (Net)
■ FEE ACREAGE (Net)
△ PRODUCING WELLS (Net)
2002 DRILLING ACTIVITY AREAS
OFFICE LOCATIONS
FEBRUARY 2003

East Texas and Louisiana

Bossier Play Since operations began in 1996, the Company has discovered seven significant fields, achieved a development success rate of nearly 100% and expanded the Bossier play from east Texas into north Louisiana. The Bossier play consists of multiple fields and multiple pay zones. The majority of the Company's production is from the Bossier Sand interval.

During 2002, Anadarko continued drilling in the Bossier play and had a total of 14 rigs drilling (eight in east Texas and six in north Louisiana) at year-end. The Company drilled 83 wells in 2002 with a success rate of 93%. Bossier volumes for 2002 totaled 96 Bcf (net), or roughly 15% of the Company's total gas production, making it Anadarko's largest onshore gas area. Anadarko had a total of 489,000 net acres in the area at year-end 2002. During 2003, the Company expects to operate about 12 rigs (seven in east Texas and five in north Louisiana) to drill 81 wells, including at least four exploration wells, in the Bossier play. In 2003, total spending in the Bossier play is expected to be $251 million, which includes $12 million for exploration.

In the east Texas Bossier, Anadarko has drilled 473 wells and had a total of 359,000 net acres as of the end of 2002. During 2002, the Company's net gas production averaged 192 MMcf/d from the Bossier play of east Texas. Despite the significant reduction in drilling during 2002 — the Company drilled 56 wells compared to over 140 wells in 2001 — production declines were modest due to the Bossier field's production characteristic as a long-life asset. Exploration continued at a steady pace during 2002 to expand the play deeper into the basin and identify new field reserves. During 2002, a discovery was made with the Gregory A-1 well (100% working interest (WI)). One successful delineation well had been drilled as of the end of 2002 and delineation drilling continues. The Company also continued to expand the Dowdy Ranch field during 2002, drilling four successful delineation wells.

In the north Louisiana Bossier, the Vernon field was producing 70 MMcf/d of gas (net) from 78 wells at the end of 2002. Anadarko has extended the Vernon field significantly over the past three years through successful drilling. A total of 27 wells were drilled in the Vernon/Ansley area in 2002, with a 96% success rate. A 3-D seismic survey is being acquired in order to help identify exploration prospects. At year-end 2002, Anadarko's position in the play totaled 130,000 net acres.

Carthage Anadarko is conducting a successful development program in the Carthage area. The Company drilled eight Cotton Valley infill wells during 2002. Anadarko has additional infill locations to drill and is studying the potential for increased well density in the area. The Company had five rigs performing workovers and re-completions throughout the Carthage area at the end of 2002. Anadarko's net production from the Carthage area averaged 105 MMcf/d of gas and 2 MBbls/d of liquids during 2002. The Company has budgeted $22 million and plans to drill 20 wells in the Carthage area in 2003.

South Louisiana At year-end 2002, net volumes averaged 37 MMcf/d of gas and 10 MBbls/d of oil and NGLs. Activity in the Kent Bayou field during 2002 consisted primarily of re-completing existing wells. During 2002, the Company also sold several non-core properties in other areas of south Louisiana.

Central Texas/Gulf Coast Anadarko's horizontal drilling program continues to be the focus in central Texas. During 2002, Anadarko drilled 52 wells, with a success rate of 94%, to exploit the multiple pay zones in the Giddings, Mossy Grove and Brookeland fields in central Texas. Anadarko also operates wells in the Masters Creek field located in Louisiana. The Company had a working interest ownership in 1,000,000 net acres in this area at the end of 2002, which was largely held by production. During 2002, net volumes averaged approximately 158 MMcf/d of gas, 16 MBbls/d of oil and 2 MBbls/d of NGLs. In 2002, Anadarko operated over 1,500 wells in this area. In 2003, Anadarko expects to drill 62 wells, including two exploratory wells, as part of a six-rig program. The Company has budgeted approximately $134 million for these projects in 2003.

The Company continued its cost-efficient horizontal re-entry program in the Giddings field. The cost to re-enter a well is about 40% less than the cost of a new well. During 2002, 33 wells were re-entered and completed. Anadarko plans to expand this program in 2003 and intends to re-enter 45 wells. Additionally, Anadarko continued its successful water-fracturing program. Approximately 90 wells were stimulated in 2002 and over 100 wells are expected to be stimulated in 2003.

During 2002, the Company continued development and exploration in the Mossy Grove field. The 2003 drilling program will continue to evaluate the potential of this multi-pay area.

Anadarko's development program included the drilling and completion of six wells in 2002 in the Brookeland field, where the Company has a working interest ownership in nearly 170,000 net acres. In 2003, the Company plans to continue development and looks to extend this field through increased drilling activity and water-fracture stimulation as well as the evaluation of a re-entry program similar to the Giddings field.

Permian Basin During 2002, Anadarko drilled 71 wells with a 99% success rate in the Permian basin. Two exploration wells were drilled — one was a discovery that tested at 5 MMcf/d of gas and the other is being tested. Evaluation continues and additional exploration drilling is planned for 2003. In addition, the Company performed 237 workovers and re-completions and completed installation of a carbon dioxide (CO_2) flood. Net production for 2002 averaged 91 MMcf/d of gas, 11 MBbls/d of oil and 2 MBbls/d of NGLs. Anadarko has interests in 419,000 gross (304,000 net) acres in the Permian basin and operates approximately 5,000 wells. During 2002, Anadarko made a strategic decision to exit some 300 non-core properties, covering 18,000 net acres, in southeast New Mexico with 2002 annual net production of about 700 thousand barrels of oil equivalent (MBOE). The properties were sold for $41 million in January 2003.

In the Ozona field, located in Texas, development continued with the Company drilling and completing 49 wells and re-completing 89 wells during 2002. In 2002, net production averaged 64 MMcf/d of gas. Anadarko operates about 1,900 wells in the Ozona field and plans to drill 52 new wells and re-complete 75 wells in 2003.

During 2002, the Company drilled 11 infill wells in the TXL North, TXL South and Goldsmith Cummins Deep waterflood units. Net production from these units averaged 3 MBbls/d of oil in 2002. Anadarko plans to drill an additional 74 infill wells in the area in 2003.

Mid-Continent

Hugoton Embayment Anadarko's drilling activities in the Hugoton Embayment, located in southwest Kansas and the Oklahoma and Texas panhandles, are focused on the deeper oil and gas zones below the shallow gas producing formations. Anadarko controls 978,000 gross (880,000 net) acres in this area and operates about 2,300 wells. The deep drilling program in Kansas and the Oklahoma panhandle utilizes 3-D seismic technology to locate oil and gas bearing zones. During 2002, the Beaver River field was a new discovery in Oklahoma. Success was also achieved drilling in the Ryus and Many Creeks fields in Kansas.

The Company's net production from the Hugoton Embayment area during 2002 averaged 170 MMcf/d of gas and 17 MBbls/d of oil, condensate and NGLs. In 2002, the Company drilled 32 deep wells with a 66% success rate. Anadarko also re-completed 16 wells and carried out workover operations on 126 wells in the area. In 2003, the Company has budgeted $22 million in the area and plans to drill about 26 wells.

Texas Panhandle During 2002, the Company produced an average of 24 MMcf/d of gas (net) from 218 wells completed in the Brown Dolomite or Red Cave formations in the West Panhandle field. This gas is exceptionally rich in NGLs, producing 40 barrels of NGLs per million cubic feet (MMcf) of gas in the Red Cave wells and 145 barrels of NGLs per MMcf of gas in the Brown Dolomite wells.

Central Oklahoma During 2002, net production from central Oklahoma was 25 MMcf/d of gas and 3 MBbls/d of oil. While continuing to develop the deeper gas producing zones, the majority of Anadarko's focus in 2002 has been developing a shallower oil play located in the Rush Creek field. In 2002, Anadarko drilled and completed 11 wells in the field resulting in a net production increase of 1 thousand barrels of oil equivalent per day (MBOE/d). During 2003, the Company has budgeted $15 million to drill about 20 wells in central Oklahoma. Anadarko plans to continue development in the Rush Creek and traditional deep gas areas.

Western States

Overview Anadarko continues to increase its activity level and production in the western states area, with significant exploration and development activity in conventional and coalbed methane (CBM) plays. The western states area primarily includes the Company's oil and gas properties in the Land Grant area of Wyoming, Colorado and Utah. Economics on the Land Grant acreage are greatly enhanced by Anadarko's fee mineral ownership position. For example, in a typical non-operated well that is outside of the Land Grant, Anadarko may have a 25% working interest with a 20% net revenue interest. However, on the Land Grant, because of the Company's fee mineral ownership, Anadarko may have a 25% working interest with a 33.75% net revenue interest. Anadarko's operations on the Land Grant are concentrated in the Green River basin and the Overthrust area.

The Company currently has approximately 8,878,000 gross (8,313,000 net) acres, principally attributable to its Land Grant ownership. Anadarko and its partners drilled 184 wells in the area in 2002 with an overall success rate of 98%. Anadarko's 2002 net production from the western states area averaged 307 MMcf/d of gas, 9 MBbls/d of oil and 14 MBbls/d of NGLs. Anadarko plans to invest about $237 million in the western states area for exploration and development in 2003. The Company's 2003 plans include drilling 277 development and 2 exploratory wells in Wyoming, Colorado and Utah.

Acquisitions In December 2002, Anadarko acquired Howell for approximately $258 million, including the bank debt of Howell, which was $53 million. The Company booked 64 MMBOE of proved reserves, primarily in the Salt Creek and Elk Basin fields, related to this acquisition. Howell's net production of about 12 MBOE/d is primarily from the western states area. In a separate transaction, Anadarko acquired the rights to purchase significant quantities of CO_2 and the exclusive rights to market and transport the CO_2 into the Powder River basin for $3 million and certain future consideration based on the performance of the pipeline. The Company expects to invest an additional $200 million over the next four years for the development and installation of a CO_2 enhanced oil recovery project. Anadarko plans to build a 125 mile pipeline that would deliver CO_2 to the enhanced oil recovery project in the Salt Creek field and potentially could serve other enhanced oil recovery projects in Wyoming as well. These projects are expected to result in an increase in net production from the Salt Creek field from 5 MBOE/d to 35 MBOE/d by the end of 2006.

Wyoming During 2002, Anadarko's net production from its properties located in Wyoming averaged 221 MMcf/d of gas, 5 MBbls/d of oil and 11 MBbls/d of NGLs. In the Green River basin of Wyoming, Anadarko focused on conventional drilling projects in the Wamsutter and Brady areas. In 2002, the Company drilled or participated in 123 wells in the Green River basin, with an overall success rate of 98%. In 2003, the Company plans to spend $65 million to drill 93 additional wells in the area. During 2002, Anadarko drilled 17 operated development wells (88% average WI) and participated in 93 outside-operated wells (23% average WI) in the Wamsutter area. In 2003, the Company plans to double the number of operated wells drilled.

During 2002, the Company acquired 585 miles of new proprietary 2-D seismic data in the Hanna basin and the Overthrust Belt. Anadarko continues to process and interpret this seismic data to identify new plays and prospects in the under-explored basins of southern Wyoming. In 2003, the Company plans to drill two exploration wells based on this new seismic data. During 2002, the Bureau of Land Management approved the Fort Steele Federal Development Contract in the Hanna basin area. The Company holds a working interest ownership in 760,000 gross and net acres in this area. Anadarko drilled or participated in five exploratory wells in the western states area in 2002 — three are being evaluated and two were unsuccessful.

Coalbed Methane Production from the Company's CBM properties continued to increase during 2002. At year-end 2002, net production averaged 61 MMcf/d of gas compared to 34 MMcf/d of gas in 2001. CBM gas production is expected to steadily increase over the next several years. In 2003, the Company plans to continue to explore for and develop CBM reserves and has budgeted $38 million to drill 130 wells.

The Company's Big George project in the Powder River basin of Wyoming started in late 2001. At year-end 2002, the project was producing 9 MMcf/d of gas (net) from 74 wells. During 2002, the Company drilled three wells in the Helper and Drunkard's Wash fields in Utah, with a success rate of 100%.

The Company continues to evaluate new CBM exploration opportunities on the Land Grant. During 2002, an Anadarko-operated pilot program was initiated at Copper Ridge in Wyoming (50% WI) to test the productivity of the Almond coal formation at a depth of about 3,200 feet. Four pilot wells were drilled and were producing 200 Mcf per day of gas at year-end 2002. Additionally, along the Land Grant, Anadarko entered into a 50/50 joint venture to develop 133,300 acres for CBM in the Atlantic Rim project area. Anadarko will operate 36 wells with first production expected in early 2003 and plans to drill 32 additional wells throughout the year within the joint venture.

Alaska

Overview Anadarko's activity in Alaska is concentrated primarily on the North Slope. The Company had interests in 3,144,000 gross (1,162,000 net) undeveloped lease acres, 25,000 gross (6,000 net) developed lease acres and 16,000 gross (8,000 net) fee acres in Alaska at year-end 2002. In addition, the Company is finalizing agreements on leases covering 181,000 gross (60,000 net) acres in the Foothills area of the North Slope from Arctic Slope Regional Corporation under an exclusive option-to-lease agreement, under which Anadarko also retains the right to acquire leases on an additional 1,941,000 gross (647,000 net) acres. During 2002, Anadarko announced that it was the apparent high bidder on a total of 34 tracts in the National Petroleum Reserve-Alaska (NPR-A) Oil and Gas Lease Sale 2002. The 34 tracts cover more than 282,000 gross (96,000 net) acres and are located primarily west of the Company's Moose's Tooth discovery. Including the acres from the 2002 lease sale, Anadarko's leasehold in NPR-A totals about 910,000 gross (289,000 net) acres. In total, Anadarko had access to approximately 5,380,000 gross (1,923,000 net) acres in Alaska through current and pending leases or options.

North Slope

Development The Alpine field (22% WI) on Alaska's North Slope produced an average of 96 MBbls/d of oil (gross) in 2002. A facility expansion to increase produced water handling in the field and eliminate minor oil train bottlenecks, scheduled to be completed in 2004, should increase production capacity to 110 MBbls/d. As of year-end 2002, 33 production wells and 32 injection or service wells had been completed. When completed, the entire Alpine development program is expected to have 94 horizontal wells from two drill sites.

During 2002 at Colville Delta 2, the drill site used to develop the western part of the field, development drilling continued with 19 wells (8 production and 11 injection wells) drilled and completed. The Nanuq and Fiord satellites (22% WI), previous discoveries near Alpine, are expected to be developed and produced through the Alpine facility beginning in 2006, filling in the natural production decline of Alpine.

Exploration During the 2001-2002 winter exploration season, the Company participated in the drilling of six wells. Four wells were located in the NPR-A and two in the Central Arctic. The Lookout #2 well successfully appraised the Lookout discovery. The well encountered the Alpine equivalent reservoir and tested at 4 MBbls/d of oil and 8 MMcf/d of gas after fracture stimulation. The Altamura #1, the Company's first operated well on the North Slope, encountered pay with low permeability and was temporarily abandoned. Results from the other wells have not yet been released. The Spark, Moose's Tooth and Rendezvous accumulations that have been identified within the vicinity require further delineation drilling and testing. An Environmental Impact Study has been initiated in cooperation with the Bureau of Land Management as the first step towards approval of development of reserves at the Spark, Lookout, Nanuq, Fiord and West Alpine fields.

During 2002, the Company participated in the acquisition of proprietary 3-D seismic in the NPR-A preparing for lease sales and 2003 drilling activity. The Company also acquired 2-D seismic and proprietary 3-D seismic in the Foothills.

During the 2002-2003 winter drilling season, Anadarko expects to participate in two exploration projects, the Puviaq prospect (40% WI), located near Teshekpuk Lake in the NPR-A and the Oberon prospect, an Alpine satellite opportunity. Anadarko is also planning to acquire proprietary 2-D seismic data in the Foothills and participate in the acquisition of proprietary 3-D seismic around the Alpine field. The Company will operate a drilling program to study the feasibility of producing methane hydrates from the arctic tundra. This program will utilize Anadarko's self-contained, elevated drilling platform called the Arctic Platform Drilling System, which is designed to be lightweight, modular and mobile. This system is intended to be utilized in logistically challenging areas with minimal surface impact, potentially extending traditional drilling seasons.

Cook Inlet During 2002, the Company sold all of its Cook Inlet holdings including 41,000 net acres and net proved reserves of less than 1 MMBOE with no production.

Gulf of Mexico

Overview At year-end 2002, about 8% of the Company's proved reserves were located offshore in the Gulf of Mexico. Net production volumes in 2002 from these properties averaged 230 MMcf/d of gas and 16 MBbls/d of oil, condensate and NGLs. At year-end 2002, Anadarko owned an average 70% interest in 371 blocks representing 441,000 gross (204,000 net) acres in developed properties and 1,450,000 gross (1,126,000 net) acres in undeveloped properties in the Gulf of Mexico. Anadarko also holds options to earn working interests covering an additional 106 blocks. During 2002, Anadarko participated in 23 wells in the Gulf of Mexico: 9 shelf conventional, 7 sub-salt and 7 deepwater wells. Drilling results in the Gulf of Mexico included 9 gas wells, 9 oil wells and 5 dry holes for a success rate of 78%. In the Gulf of Mexico, Anadarko has budgeted about $460 million for capital spending in 2003, which includes drilling about 40 wells.

Shelf Conventional Shallow water projects in the Gulf of Mexico continue as the Company exploits the potential around several of its larger and more mature fields. Ongoing re-processing of seismic and re-mapping have generated numerous prospects, adding to the Company's large inventory of projects identified from extensive field studies. During 2002, nine successful wells were drilled for a 100% success rate. Anadarko has interests in a total of 93 blocks on the shelf.

Activity in 2002 was highlighted by the Company's continued success at South Marsh Island (SMI) 280/281 (30-50% WI). During 2002, the ''H'' and ''I'' platforms at SMI 280/281 were completed. Additional drilling and workovers are planned for 2003, including several deep tests. In 2003, the Company is planning to drill 18 development and three exploratory wells near its older existing fields.

Sub-Salt During 2002, Anadarko continued to delineate the Tarantula (100% WI) sub-salt discovery made during 2001, which is located on South Timbalier 308. The #2ST#1 confirmation well was drilled and encountered 153 feet of net pay in five zones. A third well was drilled in late 2002 to further delineate the discovery and encountered 44 feet of net pay in the primary zone. A fourth well drilled in 2003 encountered over 100 feet of pay in various intervals. The Company has authorized construction of an $86 million production platform during 2003 with a capacity of 100 MMcf/d of gas and 30 MBbls/d of oil. Production is expected to commence in the fourth quarter of 2004.

During 2002, production continued from the Hickory (50% WI) and Tanzanite (100% WI) sub-salt fields discovered in 1998 off the coast of Louisiana. The Hickory A-5 well, drilled in 2002, encountered 105 feet of net pay in four sands and has been completed in a deeper pay interval. This additional development well should increase production rates of the field and more effectively drain the reservoir.

Anadarko has commenced installation of equipment for the Pardner (100% WI) sub-sea tieback. First production, from this 2001 discovery, is expected during the second quarter of 2003 at a rate of 3 MBbls/d of oil.

Anadarko has interests in a total of 114 blocks in its sub-salt program, with 38 prospects identified. An additional 11 blocks could be earned within its option program. Three exploratory wells and six development wells are planned in the sub-salt for 2003.

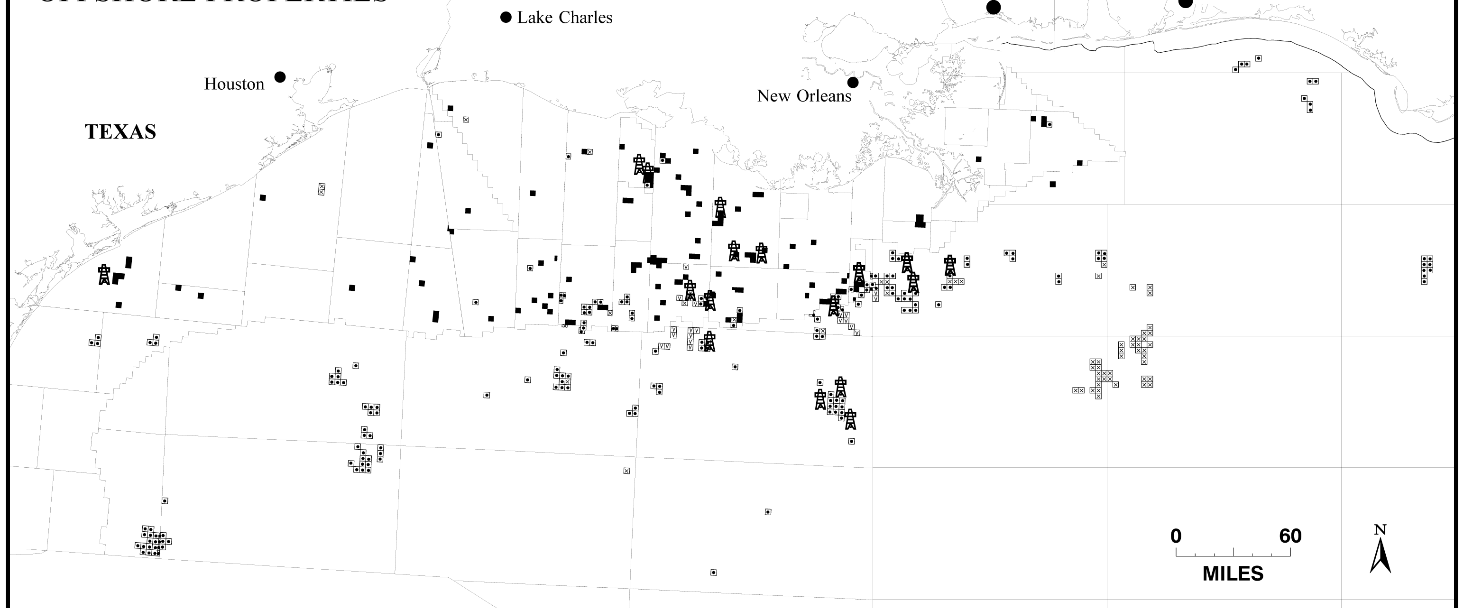
Deepwater Marco Polo (100% WI), Anadarko's first deepwater development project, is located on Green Canyon Block 608 in 4,300 feet of water approximately 180 miles offshore Louisiana in the Gulf of Mexico. Anadarko made the Marco Polo discovery in 2000. During 2002, four development wells were drilled and had better than expected results — thicker pay and higher quality sands. Anadarko drilled two additional development wells at Marco Polo in early 2003, both of which were successful.

In April 2002, the Company signed an agreement under which a production platform for its Marco Polo discovery, as well as other nearby fields, will be installed. The other party to the agreement will construct and own the platform and production facilities. Production capacity of the facility will be 120 MBbls/d of oil and 300 MMcf/d of gas, which is greater than expected production from Marco Polo. Anadarko will have firm capacity of 50 MBbls/d of oil and 150 MMcf/d of gas. The platform is currently under construction and installation is planned for late 2003. When completed, Anadarko will be the operator of the platform. Production is expected to commence in the first quarter of 2004.

During 2002, Anadarko and its partners announced a successful deepwater sub-salt appraisal well at K2 on Green Canyon Block 562 (52% WI) in the Gulf of Mexico, approximately six miles northwest of Marco Polo. The K2 #2 well encountered a total of 339 feet of oil pay in three sands in an untested fault block and reached target depth of 25,700 feet. The well extends the limits of the discovery on the K2 structure. Additional appraisal operations will continue in 2003.

Anadarko Petroleum Corporation

OFFSHORE PROPERTIES



- 2002 DRILLING ACTIVITY
- ■ PRODUCTION BLOCKS
- □ DEVELOPMENT BLOCKS
- ⊡ EXPLORATORY BLOCKS
- ⊠ 2002 LEASE ACQUISITIONS
- ⊽ 1999 TEXACO LEASE BLOCKS NOT ASSIGNED

OFFSHORE ACREAGE	TEXAS	LOUISIANA	FLORIDA	MISSISSIPPI	CALIFORNIA
UNDEVELOPED (Net)	315,336	451,502	189,590	169,909	2,785
DEVELOPED (Net)	28,230	172,237	—	3,996	—
PRODUCING WELLS (Net)	43	156	—	—	—

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Anadarko has submitted plans of exploration to the Minerals Management Service on four deepwater prospects located in the eastern portion of the Gulf of Mexico, of which three are within and one is partially adjacent to the Lease Sale 181 area (see *Lease Sales).* Three of the permits have been approved and drilling began in early 2003.

Anadarko holds a total of 164 lease blocks in its deepwater program and has identified 29 prospects. An additional 95 blocks could be earned within its option program. Five deepwater exploratory wells are planned for 2003.

South Auger Participation Agreement Anadarko has a Participation Agreement with BP to explore 95 deepwater blocks in the Garden Banks and Keathley Canyon areas of the western Gulf of Mexico. The 95 blocks, held 100% by BP, are within a larger 640-block area of mutual interest where the two companies will license and reprocess 3-D seismic data. These blocks are in water depths ranging from 3,000 to 6,000 feet. The agreement gives Anadarko the option to earn a 33% to 66% working interest in the blocks. Anadarko will fund 100% of the licensing and re-processing costs and pay a disproportionately larger share of the first four wells drilled.

Lease Sales In January 2002, Anadarko acquired 26 tracts (100% WI) in the Eastern Gulf of Mexico Lease Sale 181. The Company's total investment was $136 million. The 26 tracts cover nearly 150,000 acres in water depths ranging from 7,000 to 9,500 feet. The blocks included in Lease Sale 181 have not been available for exploration since 1988, long before major advancements occurred in seismic imaging and deepwater drilling and development technology. The Company is considering taking on partners to recover lease costs and reduce risk. Anadarko also acquired nine tracts (100% WI) covering about 42,000 acres at Gulf of Mexico Lease Sales 182 and 184 held during 2002. The Company's total investment was about $3 million.

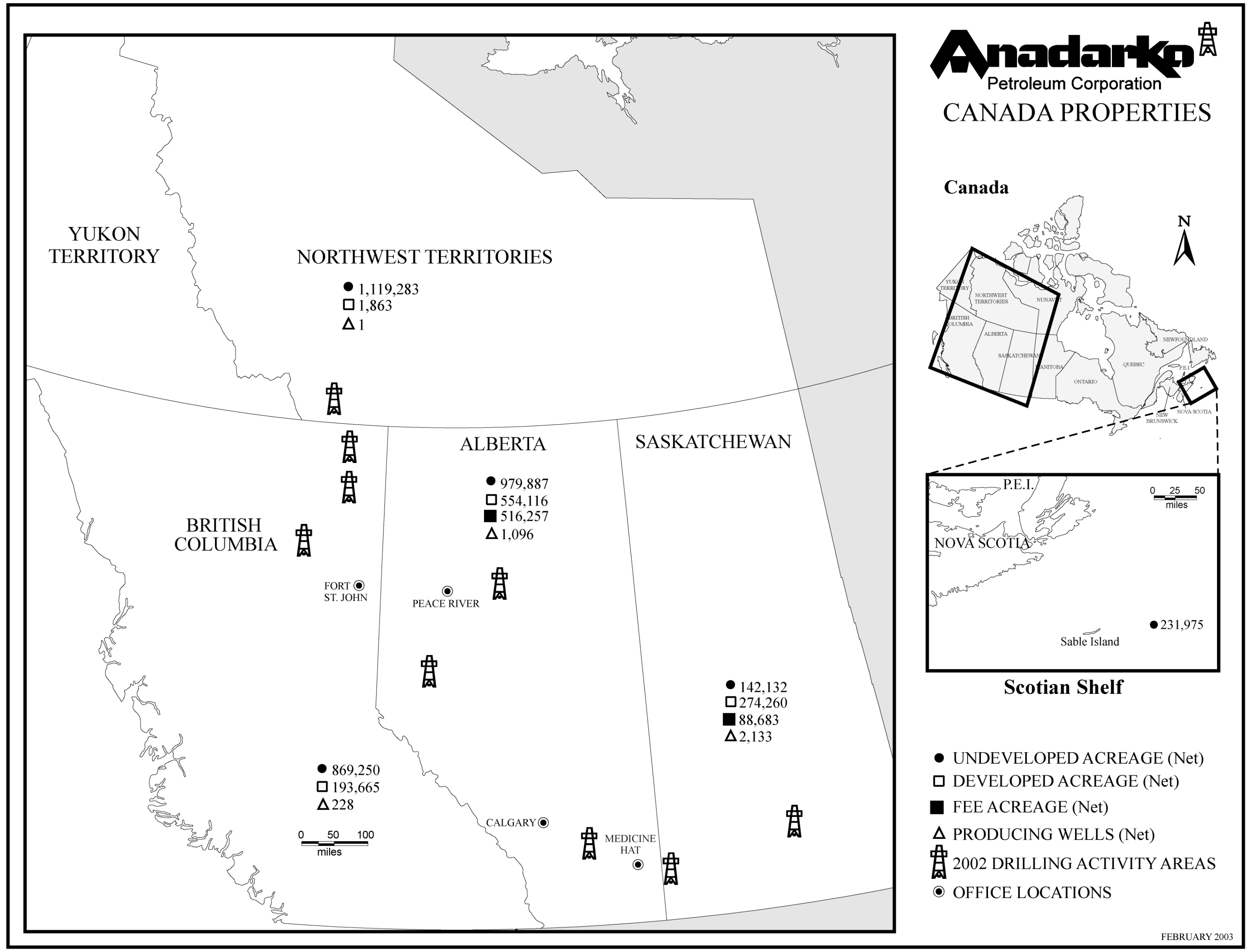
Gas Processing

The Company processes gas at various third-party plants under agreements generally structured to provide for the extraction and sale of NGLs in efficient plants with flexible commitments. The Company has agreements with four plants in the western states area, 14 plants in the mid-continent area and 11 plants in the gulf coast area. Anadarko also processes gas and has interests in three Company-operated plants and three non-operated plants in the western states. Anadarko's strategy to aggregate gas through Company-owned and third-party gathering systems allows Anadarko to secure processing arrangements in each of the regions where the Company has significant production.

Properties and Activities — Canada

Overview Anadarko has operations in Alberta, British Columbia, Saskatchewan and in the Northwest Territories. The Company has proved reserves in Canada of 288 MMBOE, which includes 1.3 Tcf of gas and 64 MMBbls of crude oil, condensate and NGLs. In 2002, net production from the Company's properties in Canada averaged 370 MMcf/d of gas and 35 MBbls/d of crude oil, condensate and NGLs, or 18% of the Company's total production volumes. During 2002, Anadarko participated in a total of 391 wells with a 97% success rate, including 294 gas wells, 84 oil wells and 13 dry holes. Anadarko has 9,357,000 gross (3,343,000 net) undeveloped lease acres, 1,811,000 gross (1,024,000 net) developed lease acres and 605,000 gross (605,000 net) fee acres in Canada.

The Company significantly increased its exploration activity in Canada during 2002, participating in 46 wells with an 83% success rate. As one of the most active drillers in Canada, Anadarko reached a peak of 26 operated rigs with 10 rigs drilling exploratory wells during 2002. The Company's 2003 capital budget of $360 million for Canada includes approximately $250 million for development drilling and infrastructure and $110 million for exploration, including approximately 43 exploration wells. The accompanying map illustrates the Company's developed and undeveloped lease and fee acreage, number of productive wells and other data relevant to its properties in Canada.


Anadarko
Petroleum Corporation
CANADA PROPERTIES
Canada
N
YUKON TERRITORY
NORTHWEST TERRITORIES
● 1,119,283
□ 1,863
Δ 1
BRITISH COLUMBIA
● 869,250
□ 193,665
Δ 228
ALBERTA
● 979,887
□ 554,116
■ 516,257
Δ 1,096
SASKATCHEWAN
● 142,132
□ 274,260
■ 88,683
Δ 2,133
FORT ST. JOHN
PEACE RIVER
CALGARY
MEDICINE HAT
0 50 100
miles
P.E.I.
NOVA SCOTIA
0 25 50
miles
● 231,975
Sable Island
Scotian Shelf
● UNDEVELOPED ACREAGE (Net)
□ DEVELOPED ACREAGE (Net)
■ FEE ACREAGE (Net)
Δ PRODUCING WELLS (Net)
2002 DRILLING ACTIVITY AREAS
OFFICE LOCATIONS
FEBRUARY 2003

Alberta During 2002, production in the Saddle Hills area of northern Alberta reached a record 64 MMcf/d of gas after a natural gas pipeline was completed to a processing plant and wells were tied in. A total of 12 net wells were completed during 2002. In addition, Anadarko increased its position in the area by over 37,000 net acres during the year and acquired 86 square miles of 3-D seismic.

In the Alberta Foothills, a horizontal gas well was completed and tested at a rate of about 6 MMcf/d of gas. Anadarko participated in a second well in the Alberta Foothills that tested at about 7 MMcf/d of gas. In the Wild River area of west central Alberta, 21 wells were completed during 2002. Net production from the Wild River area was 34 MMcf/d of gas and 400 barrels per day of NGLs at the end of 2002. Regulatory approval for commingling production zones was obtained in 2002, allowing Anadarko to immediately complete up to six zones per well. In the Dawson oil field in northwest Alberta, 20 wells were completed in 2002.

During 2002, Anadarko sold its heavy oil assets in eastern Alberta in several separate transactions for a total of about $160 million. The sale included 28 MMBOE of net proved reserves and production of approximately 21 MBOE/d.

British Columbia During 2002, in northeast British Columbia, two operated proprietary 3-D seismic programs were conducted over the Jedney and Adsett areas. The Company continued to experience success throughout the year in the Slave Point play. Several exploratory wells were completed and brought on production at an average rate of approximately 5 MMcf/d of gas.

In the British Columbia Foothills, the Monkman b-79-J (30% WI) discovery was tied in and came on production at an initial rate of 15 MMcf/d of gas. An offset well began drilling in the fourth quarter of 2002. In the evolving West Blueberry tight gas play, Anadarko brought four new wells on-line at an average rate of 5 MMcf/d of gas.

Saskatchewan During 2002, the Company drilled and completed 203 shallow gas wells with an overall success rate of 100%. In the Hatton area, the Company drilled 168 operated wells and participated in another 28 non-operated wells. Net production from the Hatton area averaged 73 MMcf/d of gas in 2002.

Northwest Territories Anadarko completed two proprietary 3-D seismic programs and a proprietary 2-D seismic program in the southern Northwest Territories near Fort Liard in 2002. The Netla A-68 well drilled in 2002 was a discovery.

Anadarko also completed a 122 mile proprietary 2-D seismic program over Block 407 (100% WI) and participated in three additional proprietary seismic programs in the Mackenzie Delta.

Properties and Activities — Algeria

Overview Anadarko is actively developing and producing oil fields discovered by the Company in Algeria's Sahara Desert. Since 1989, Anadarko has participated in 99 productive wells (13 exploration and 86 delineation/development) located in 13 fields in Algeria. Eight of the fields are actively being developed and are on production. Final approval to develop four of the fields has been requested and is pending government approval. One field was recently discovered and a Commerciality Report is being prepared. Anadarko has developed a good working relationship with Sonatrach, the national oil and gas enterprise of Algeria, its partner in all development projects within Algeria. Sonatrach has owned shares of the Company's common stock since 1986 and at year-end 2002 was the registered owner of 4.9% of Anadarko's outstanding common stock.

The Company has proved reserves in Algeria of 372 MMBbls of crude oil as of year-end 2002. In 2002, net sales volumes from the Company's properties in Algeria totaled 24 MMBbls of crude oil, or 12% of the Company's total sales volumes.

In 2002, Anadarko participated in 34 wells with a success rate of 88%. Anadarko plans to invest about $98 million in Algeria in 2003. At the end of 2002, the Company had 3,994,000 gross (1,221,000 net) acres in Algeria. The accompanying map illustrates the Company's developed and undeveloped acreage, number of productive wells and other data relevant to its properties in Algeria.

Anadarko Petroleum Corporation

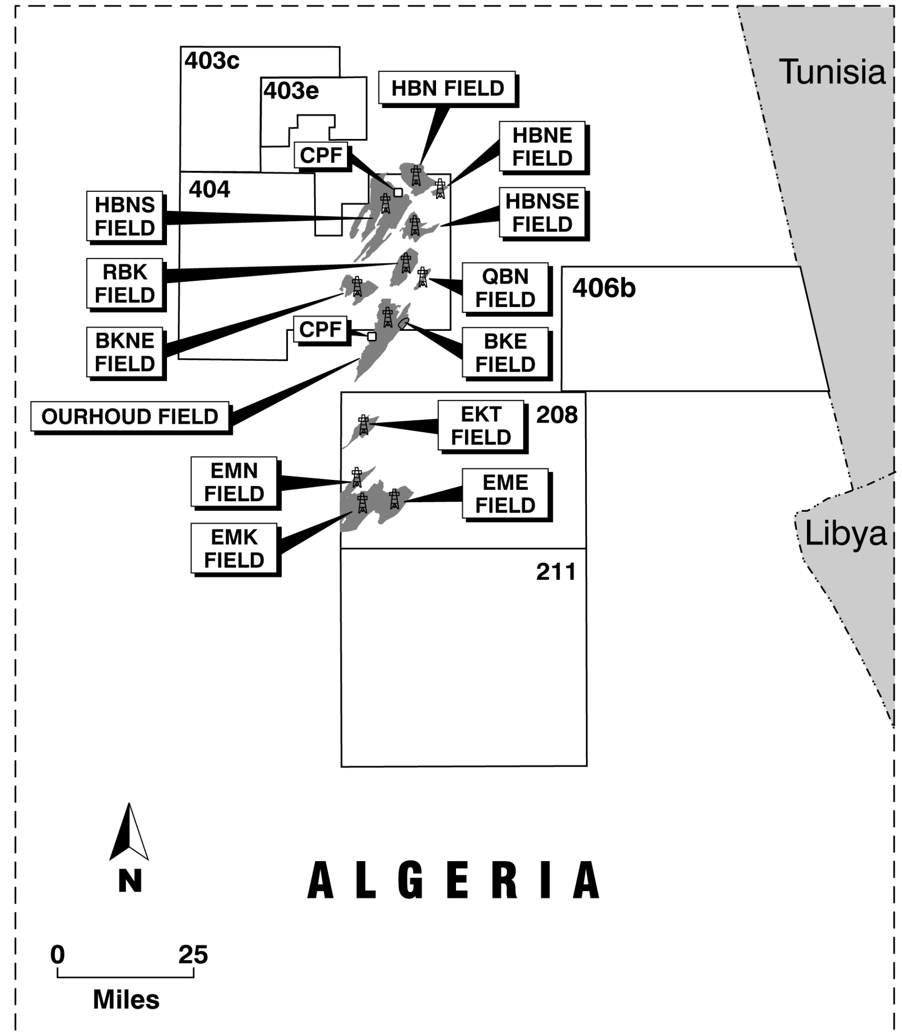
ALGERIAN PROPERTIES

Algeria Undeveloped Acreage
Total 3.8 million acres (1.2 million acres net)

Algeria Developed Acreage (HBNS, HBN, Ourhoud, HBNSE, BKNE, RBK, QBN & BKE Fields)
Total 219,000 acres (54,000 acres net)

Productive Wells
Total 99 (21 net)

FIELDS DISCOVERED TO DATE
2002 DRILLING ACTIVITY AREAS
ANADARKO OPERATED BLOCKS
CENTRAL PROCESSING FACILITY (CPF)



FEBRUARY 2003

Contracts/Partners

Blocks 404, 208 and 211 Production Sharing Agreement Anadarko's interest in the original production sharing agreement (PSA) is 50% before participation at the exploitation stage by Sonatrach. The Company has two joint venture partners, each with a 25% interest in the Algerian venture, also prior to participation by Sonatrach. Under the terms of the PSA, oil reserves that are discovered, developed and produced are shared by Sonatrach, Anadarko and its two joint venture partners. Anadarko and its joint venture partners funded Sonatrach's 51% share of exploration costs and are entitled to recover these exploration costs out of production in the exploitation phase. As of year-end 2002, Anadarko and its joint venture partners had recovered about 93% of Sonatrach's portion of exploration costs through an increased share of production (cost recovery oil) with the majority of the remaining 7% expected to be recovered during 2003. Sonatrach is responsible for 51% of development and production costs. Sonatrach and Anadarko formed a non-profit company, Groupement Berkine, to carry out the majority of their joint operating activities under the PSA. Sonatrach and Anadarko fund the expenditures incurred by Groupement Berkine according to their participating interests under the PSA. The exploration phase of the original PSA ended in 1998. In 2001, Anadarko and its partners signed an amendment to the PSA with Sonatrach, which allows exploration to resume on Blocks 404, 208 and 211. *See Exploration.*

Block 406b Production Sharing Agreement The Company has a separate exploration license for Block 406b in which Anadarko had a 100% interest. During 2002, the Company finalized an agreement to farm-out a 40% working interest in this block.

Block 403c/e Production Sharing Agreement In 2002, Anadarko was awarded exploration rights over Block 403c/e. Anadarko will hold a 67% interest in the exploration phase of this venture.

Development

Block 404 — Hassi Berkine South Central Production Facility Production from the Hassi Berkine South (HBNS) field averaged 125 MBbls/d of oil (gross) in 2002 compared to 77 MBbls/d of oil (gross) in 2001. The fourth processing unit was completed in April 2002, bringing the total HBNS facility capacity to 300 MBbls/d of oil. During 2002, three of the satellite fields – Hassi Berkine South East (HBNSE), Berkine North East (BKNE) and Rhourde Berkine (RBK) – commenced production and averaged 22 MBbls/d of oil (gross). During 2002, 17 wells were drilled in the HBNS and satellite fields, resulting in 16 productive wells and one unsuccessful well.

Groupement Berkine is also developing the Hassi Berkine (HBN) field that is located just to the north of the HBNS field. This producing field extends into Block 403, which is under a different association with Sonatrach. Unitization of the field was accomplished to facilitate development activities. A crude oil production train with the capacity to process 75 MBbls/d of oil has been installed as part of the HBNS facility. Production from the HBN field averaged 67 MBbls/d of oil (gross) in 2002. During 2002, three productive wells were drilled in the HBN field with a 100% success rate.

Block 404 — Ourhoud Central Production Facility Anadarko is also actively involved in developing the Ourhoud field, the second largest oil field in Algeria. Located in the southern portion of Block 404, the Ourhoud field extends into Block 406a and Block 405 and is unitized with the companies with interests in those blocks. The field is operated by the Ourhoud Organization, which represents the interests of the three associations involved in this development. Production from the field commenced in November 2002 two months ahead of schedule and reached rates of 71 MBbls/d of oil (gross) by year-end 2002. Ourhoud is expected to be fully operational during the first half of 2003 with facility capacity reaching 230 MBbls/d of oil. During 2002, a total of six productive wells were drilled in the Ourhoud field.

Block 208 Anadarko also has several fields farther south on Block 208; these include the El Merk field (EMK), the El Kheit Et Tessekha field (EKT), the El Merk East field (EME) and the El Merk North field (EMN). During 2002, Sonatrach approved the Commerciality Reports for these fields and the Exploitation License Applications were submitted to the Ministry of Energy and Mines for approval. Once the Exploitation Licenses are approved, Anadarko will proceed with design and construction of a third Central Production Facility. During 2002, a total of five wells were drilled in the Block 208 fields, resulting in four productive wells and one unsuccessful well.

Exploration The 1989 PSA, as amended in 2001, allows Anadarko and its joint venture partners to resume exploration on Blocks 404, 208 and 211, outside of the exploitation license boundaries encompassing the previous discoveries. These are the same blocks Anadarko and its joint venture partners began exploring in 1989 and the new agreement allows Anadarko to build on the knowledge gathered since then using current state-of-the-art technology to commence a new phase of exploration.

Under the terms of the three-phase exploration program, Anadarko and its joint venture partners will spend a minimum of $55 million. Anadarko and its joint venture partners will finance 100% of the exploration investment and Sonatrach will participate 51% in the development and exploitation phases of any discoveries. Where appropriate, existing facilities and infrastructure may be used to develop any discoveries. To date, 640 miles of proprietary 2-D seismic data have been acquired following the PSA amendment, which is under evaluation.

During 2002, Anadarko and its joint venture partners drilled three exploration wells one of which was successful. The Hassi Berkine North East (HBNE) #1 well, located in Block 404, just east of the HBN field, resulted in an oil discovery. A production test conducted in January 2003 flowed at a rate of 4 MBbls/d of oil. The Company is evaluating options for connecting this discovery to existing infrastructure. A fourth exploration well, Sif Fatima South West #1 located in Block 404, was drilled in early 2003 and the results are currently being evaluated.

The license for Block 406b has a three-year initial term. A work program commitment includes seismic acquisition and one exploration well. A 735 mile proprietary 2-D seismic acquisition program has been completed on this 686,000 acre block, located in the Berkine basin to the east of Anadarko's other license areas.

The license for Block 403c/e has a three-year initial term and increases Anadarko's gross acreage position by 399,000 acres in the Berkine basin. A work program commitment includes seismic acquisition and one exploration well.

Political unrest continues in Algeria. Anadarko continually monitors the situation and has taken reasonable and prudent steps to ensure the safety of employees and the security of its facilities in the remote regions of the Sahara Desert. Anadarko is unable to predict with certainty any effect the current situation may have on activity planned for 2003 and beyond. However, the situation has had no material effect to date on the Company's operations in Algeria, where the Company has had activities since 1989. See *Regulatory Matters and Additional Factors Affecting Business — Foreign Operations Risk* under Item 7 of this Form 10-K.

Properties and Activities — Other International

Overview The Company's other international oil and gas production and development operations are located primarily in Venezuela, Qatar and Oman. The Company also has interests in two non-operated offshore producing properties in Australia and an interest in a non-operated producing property in Egypt. The Company currently has exploration projects in Tunisia, Qatar, Oman, Gabon, Australia, the Faroe Islands, off the coast of Georgia in the Black Sea and other selected areas.

The Company has total proved reserves in these other international locations of 117 MMBbls of crude oil, condensate and NGLs and 144 Bcf of gas at year-end 2002. During 2002, net production from the Company's other international properties was 22 MBbls/d of crude oil, condensate and NGLs, or 4% of the Company's total production volumes. Anadarko participated in a total of 10 wells in its other international locations during 2002 with a success rate of 50%. Drilling results included five oil wells and five dry holes. Anadarko has 24,896,000 gross (10,435,000 net) undeveloped lease acres and 569,000 gross (155,000 net) developed lease acres in these international areas. See *Regulatory Matters and Additional Factors Affecting Business — Foreign Operations Risk* under Item 7 of this Form 10-K.

Venezuela The Company's Venezuelan operation consists of the Oritupano-Leona contract area, a risk service contract in which the Company has a 45% participating interest. The area covers 395,000 gross (178,000 net) acres and had approximately 272 producing wells at year-end 2002. Oil sales volumes from the area averaged 13 MBbls/d net during 2002. The development and exploitation program in 2002 included two new well completions and the conversion of 13 idle wells to producing wells. During 2003, the Company expects to continue with the development of the Oritupano-Leona contract area, focusing most of the activities on re-completing wells and increasing fluid handling capacities within the field.

Currently, there is political unrest in Venezuela. Due to a national strike, production deliveries from the Oritupano-Leona area were halted in April and December 2002. Production resumed in January 2003 at lower levels and is expected to be back at full production by the second quarter of 2003. Anadarko is unable to predict with certainty any effect the current situation may have on activity planned for 2003 and beyond. However, the situation is not expected to have a material adverse effect on the consolidated results of operations or financial position of the Company.

Qatar The Company acquired an additional interest and took over operatorship of offshore Qatar Blocks 12 and 13 during 2002. Anadarko now has a 92.5% interest in the Al Rayyan field, which is part of an Exploration and Production Sharing Agreement covering Blocks 12 and 13. Production from the Al Rayyan field, which is located in the northern part of Block 12, averaged 14 MBbls/d of oil (7 MBbls/d net) during 2002. The horizontal wells for the phase I field re-development were completed in 2002. In addition, process and utilities modules were constructed and installed on a permanent production facility. Approximately $40 million is budgeted for 2003 to complete the construction and installation of this offshore production facility, perform phase II development drilling and drill an exploration well on the southern part of Block 12. Following phase II, field production is expected to more than double. Evaluation of the remaining exploration potential of Block 12 was initiated in 2002 and should be completed in early 2003.

During 2002, the Company began a seismic feasibility study on Block 13, which will serve to define a seismic program expected to be acquired in 2003.

Anadarko also has a 49% interest in an Exploration and Production Sharing Agreement covering offshore Block 11. During 2002, an evaluation of the remaining exploration potential on Block 11 was performed. The results of that study have been presented to Qatar Petroleum, with additional discussions scheduled for early 2003.

Oman Anadarko is the operator of an exploration and development project in the Hafar field on Block 30 in Oman. Anadarko plans to drill two wells in 2003. The first exploration well, Hamrat Duru #3, began drilling in February 2003 and is intended to test the gas potential of the large Hamrat Duru structure. The second well, the Nadir #2, will follow and is intended to delineate and extend the Hafar/Al Sahwa trend. Anadarko has a 100% interest in the field. Gas production will be sold to the Oman government under a long-term sales agreement.

Egypt Anadarko has a 25% non-operated interest in the Zaafarana field offshore Egypt. The Company's net volumes in Egypt for 2002 averaged 1 MBbls/d of oil.

Australia Anadarko has a 15% non-operated interest in production facilities in the Jabiru and Challis fields (ACL123) offshore Northwest Shelf. The Company's net volumes from these fields during 2002 averaged 1 MBbls/d of oil. Anadarko relinquished its interests in four licenses (ACL 4, AC/P 25, 26 and 27) in the Timor Sea following three unsuccessful wells in 2002. Anadarko has a 30% interest in four exploration permits, EPP 28, 29, 30 and 31 covering 15,500,000 gross acres offshore southern Australia in the Great Australian Bight. A deepwater exploration well is scheduled for drilling on EPP 29 in early 2003.

Tunisia The Company increased its interest from 47% to 61% in 2002 and is the operator of the 1,100,000 acre Anaguid Block in the Ghadames basin of Tunisia. The acreage is on trend with the Company's discoveries in Algeria to the west. The CEM-1 and the SEA-1 wells are expected to spud in early 2003. Both wells will target the Silurian Acacus formation. In early 2003, Anadarko completed the drilling of an unsuccessful exploration well on the Sanrhar Block.

West Africa During 2002, the Company obtained a 55% interest in the Gryphon Block, a 2,400,000 acre tract offshore Gabon in the Gamba pre-salt trend. An exploration well, the Pembi #1, is expected to spud by the third quarter of 2003.

Anadarko is the operator and holds a 50% interest in the Agali Block offshore Gabon. During 2002, 3-D seismic data was processed and evaluated. Drilling may occur in late 2003 but will be after the resolution of a boundary dispute between Gabon and its neighbor to the north, Equatorial Guinea.

Anadarko drilled one exploration well in West Africa during 2002 on the Marine IX Block offshore the Republic of Congo. The Rita #1 well encountered thin gas pay but was deemed non-commercial. The Company is considering marketing its 42% interest in the block during the first quarter of 2003.

North Atlantic Margin In the Faroe Islands, Anadarko is the operator and sole licensee of License 007 and holds a 28% interest in the adjacent non-operated License 006. The licenses cover a total of 617,000 acres. In 2002, the Company integrated seismic data as part of a comprehensive license and basin evaluation. In 2003, the Company will complete these studies and further develop a prospect inventory. The Company has no outstanding drilling commitments in the region.

In the United Kingdom Continental Shelf, Tranches 21 and 63 were relinquished in 2002. In Tranche 61, (7.5% interest) 49,000 acres surrounding two gas discoveries have been retained pending further evaluation.

Georgia — Black Sea Anadarko has a Production Sharing Contract with the State of Georgia. The agreement gives Anadarko exploration rights to three blocks covering approximately 2,000,000 acres on the Black Sea Continental Shelf and extending 50 miles offshore. In 2002, the Company evaluated proprietary seismic data and plans to seek a partner to share cost and reduce risk in future seismic or drilling activities in 2003.

Drilling Programs

The Company's 2002 drilling program focused on known oil and gas provinces in the United States (Lower 48, Alaska and Gulf of Mexico), Canada and Algeria. Exploration activity consisted of 114 wells, including 48 wells in the Lower 48, 6 wells in Alaska, 7 wells offshore in the Gulf of Mexico, 46 wells in Canada, 3 wells in Algeria and 4 wells at other international locations. Development activity consisted of 835 wells, which included 429 wells in the Lower 48, 8 wells in Alaska, 16 wells offshore in the Gulf of Mexico, 345 wells in Canada, 31 wells in Algeria and 6 wells at other international locations.

Drilling Statistics

The following table shows the results of the oil and gas wells drilled and tested:

	Net Exploratory			Net Development			
	Productive	**Dry Holes**	**Total**	**Productive**	**Dry Holes**	**Total**	**Total**
2002							
United States	**34.0**	**13.8**	**47.8**	**275.2**	**5.1**	**280.3**	**328.1**
Canada	**30.6**	**6.8**	**37.4**	**305.6**	**4.0**	**309.6**	**347.0**
Algeria	**0.5**	**1.0**	**1.5**	**7.3**	**0.7**	**8.0**	**9.5**
Other International	**—**	**3.7**	**3.7**	**3.7**	**0.9**	**4.6**	**8.3**
Total	**65.1**	**25.3**	**90.4**	**591.8**	**10.7**	**602.5**	**692.9**
2001							
United States	33.6	18.3	51.9	544.0	8.4	552.4	604.3
Canada	28.0	6.0	34.0	381.1	18.0	399.1	433.1
Algeria	—	—	—	3.5	0.2	3.7	3.7
Other International	—	2.7	2.7	11.4	—	11.4	14.1
Total	61.6	27.0	88.6	940.0	26.6	966.6	1,055.2
2000							
United States	12.9	9.0	21.9	390.8	10.4	401.2	423.1
Canada	8.9	8.0	16.9	98.1	14.4	112.5	129.4
Algeria	—	—	—	1.7	—	1.7	1.7
Other International	—	0.6	0.6	5.7	—	5.7	6.3
Total	21.8	17.6	39.4	496.3	24.8	521.1	560.5

The following table shows the number of wells in the process of drilling or in active completion stages and the number of wells suspended or waiting on completion as of December 31, 2002:

	Wells in the process of drilling or in active completion		Wells suspended or waiting on completion	
	Exploration	**Development**	**Exploration**	**Development**
United States				
Gross	4	47	12	31
Net	3.3	33.9	6.1	13.7
Canada				
Gross	11	21	2	26
Net	8.5	17.3	1.4	20.4
Algeria				
Gross	—	4	—	1
Net	—	0.9	—	0.2
Other International				
Gross	1	1	—	2
Net	1.0	0.5	—	1.9
Total				
Gross	16	73	14	60
Net	12.8	52.6	7.5	36.2

Productive Wells

As of December 31, 2002, the Company had a working interest ownership in productive wells as follows:

	Oil Wells*	**Gas Wells***
United States		
Gross	9,089	10,106
Net	6,207.0	6,420.3
Canada		
Gross	1,037	3,530
Net	646.4	2,811.4
Algeria		
Gross	99	—
Net	21.4	—
Other International		
Gross	302	—
Net	136.2	—
Total		
Gross	10,527	13,636
Net	7,011.0	9,231.7

* Includes wells containing multiple completions as follows:

Gross	191	1,682
Net	160.9	1,319.3

Marketing and Gathering Properties and Activities

Marketing The Company's marketing department actively manages sales of its oil and gas through Anadarko Energy Services Company, Anadarko, Anadarko Canada Corporation and Anadarko Holding. The Company markets its production to creditworthy customers at competitive prices, maximizing realized prices while managing credit exposure. The Company purchases some physical volumes for resale primarily from partners and producers near Anadarko's production. These purchases allow the Company to aggregate larger volumes of gas and attract larger, creditworthy customers, which in turn enhances the value of the Company's production.

The Company sells natural gas under a variety of contracts and may also receive a service fee related to the level of reliability and service required by the customer. The Company has the capability to move large volumes of gas into and out of the "daily" gas market to take advantage of any price volatility. Included in this strategy is the use of leased natural gas storage facilities and various derivative instruments. However, the Company does not engage in market-making practices nor does it trade in any non-energy-related commodities. The Company's marketing function does not engage in round-trip trades and does not participate in any marketing-related partnerships.

Gas Gathering Anadarko owns and operates seven major gas gathering systems in the United States, where the Company has substantial gas production. The systems are: Antioch Gathering System in the Southwest Antioch field of Oklahoma; Sneed System in the West Panhandle field of Texas; Hugoton Gathering System in southwest Kansas; Dew Gathering System in east Texas; Pinnacle Gathering System in east Texas; CJV/SEC Gathering System in the Carthage field of east Texas; and Vernon Gathering System in the Vernon field of north Louisiana.

The Company's major gathering systems have more than 3,000 miles of pipeline connecting about 3,300 wells and averaged more than 730 MMcf/d of gas throughput in 2002. In addition, Anadarko operates numerous other smaller gas gathering systems.

Minerals Properties and Activities

The Company's minerals properties contribute to operating income through non-operated joint venture and royalty arrangements in coal, trona and industrial mineral mines across the Company's extensive fee mineral interest in the Land Grant. The Company reinvests the cash flow from its hard minerals operations primarily into its oil and gas operations.

The Company's low sulfur coal deposits, located primarily in southern Wyoming, compete with other western coal producers for industrial and utility boiler markets, which burn the coal to produce steam used to generate electricity. Most of the Company's coal interests use the surface mining method of extraction. Because of the high extraction and transportation costs, additional development of the Company's reserves is dependent on increased coal usage in local markets. In addition to fee mineral ownership of and royalty interests in coal reserves, the Company owns a 50% non-operating interest in Black Butte Coal Company. Black Butte Coal Company produces approximately 3 million tons of coal per year.

The world's largest known deposit of trona, comprising 90% of the world's trona resources, is located in the Green River basin in southwestern Wyoming. Natural soda ash, which is produced by refining trona ore, is used primarily in the production of glass, in the paper and water treatment industries and in the manufacturing of certain chemicals and detergents. The Company owns interests in lands containing approximately 50% of these reserves and has leased a portion of those lands to companies that mine and refine trona. In addition to fee mineral ownership of and royalty interest in trona reserves, the Company owns a 49% non-operating interest in the OCI Wyoming LP soda ash refining facility near Green River, Wyoming. Among domestic producers, this facility is ranked second in soda ash capacity producing over 1 million tons per year.

Segment and Geographic Information

Information on operations by segment and geographic location is contained in *Note 13* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Employees

As of December 31, 2002, the Company had about 3,800 employees. Relations between the Company and its employees are considered to be satisfactory. The Company has had no significant work stoppages or strikes pertaining to its employees.

Regulatory Matters and Additional Factors Affecting Business

See *Regulatory Matters and Additional Factors Affecting Business* under Item 7 of this Form 10-K.

Title to Properties

As is customary in the oil and gas industry, only a preliminary title examination is conducted at the time properties believed to be suitable for drilling operations are acquired by the Company. Prior to the commencement of drilling operations, a thorough title examination of the drill site tract is conducted and curative work is performed with respect to significant defects, if any, before proceeding with operations. A thorough title examination has been performed with respect to substantially all leasehold producing properties owned by the Company. Anadarko believes the title to its leasehold properties is good and defensible in accordance with standards generally acceptable in the oil and gas industry subject to such exceptions which, in the opinion of counsel employed in the various areas in which the Company has conducted exploration activities, are not so material as to detract substantially from the use of such properties.

The leasehold properties owned by the Company are subject to royalty, overriding royalty and other outstanding interests customary in the industry. The properties may be subject to burdens such as liens incident to operating agreements and current taxes, development obligations under oil and gas leases and other encumbrances, easements and restrictions. Anadarko does not believe any of these burdens will materially interfere with its use of these properties.

Capital Spending

See *Capital Resources and Liquidity* under Item 7 of this Form 10-K.

Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Stock Dividends

Anadarko's ratios of earnings to fixed charges was 3.83 and earnings to combined fixed charges and preferred stock dividends was 3.74 for the year ended December 31, 2002. As a result of the Company's net loss in 2001, Anadarko's earnings did not cover fixed charges by $599 million and did not cover combined fixed charges and preferred stock dividends by $610 million. Anadarko's ratios of earnings to fixed charges was 7.35 and earnings to combined fixed charges and preferred stock dividends was 6.80 for the year ended December 31, 2000.

These ratios were computed by dividing earnings by either fixed charges or combined fixed charges and preferred stock dividends. For this purpose, earnings include income before income taxes and fixed charges. Fixed charges include interest and amortization of debt expenses and the estimated interest component of rentals. Preferred stock dividends are adjusted to reflect the amount of pretax earnings required for payment.

Item 2. Properties

Information on Properties is contained in Item 1 of this Form 10-K and in *Note 17 — Commitments* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Item 3. Legal Proceedings

General The Company is a defendant in a number of lawsuits and is involved in governmental proceedings arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. The Company has also been named as a defendant in various personal injury claims, including numerous claims by employees of third-party contractors alleging exposure to asbestos and benzene while working at a refinery in Corpus Christi, Texas, which Anadarko Holding sold in segments in 1987 and 1989. While the ultimate outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings will not have a material adverse effect on the consolidated financial position of the Company, although results of operations and cash flow could be significantly impacted in the reporting periods in which such matters are resolved. Discussed below are several specific proceedings.

Royalty Litigation During September 2000, the Company was named as a defendant in a case styled *U.S. of America ex rel. Harold E. Wright v. AGIP Company, et al.* (the ‘‘Gas Qui Tam case’’) filed in the U.S. District Court for the Eastern District of Texas, Lufkin Division. This lawsuit generally alleges that the Company and 118 other defendants improperly measured and otherwise undervalued natural gas in connection with a payment of royalties on production from federal and Indian lands. The case has been transferred to the U.S. District Court, Multi-District Litigation Docket pending in Wyoming. Based on the Company's present understanding of the various governmental and False Claims Act proceedings described above, the Company believes that it has substantial defenses to these claims and intends to vigorously assert such defenses. However, if the Company is found to have violated the Civil False Claims Act, the Company could be subject to a variety of sanctions, including treble damages and substantial monetary fines. Motions to dismiss on the grounds that plaintiffs did not provide new information for the government to file suit upon were filed in January 2003, with a hearing date expected in May 2003.

A group of royalty owners purporting to represent Anadarko Holding's gas royalty owners in Texas (*Neinast, et al.*) was granted class action certification in December 1999, by the 21st Judicial District Court of Washington County, Texas, in connection with a gas royalty underpayment case against the Company. This certification did not constitute a review by the Court of the merits of the claims being asserted. The royalty owners' pleadings did not specify the damages being claimed, although most recently a demand for damages in the amount of $100 million was asserted. The Company appealed the class certification order. A favorable decision from the Houston Court of Appeals decertified the class. The royalty owners did not appeal this matter to the Texas Supreme Court and the decision from the Houston Court of Appeals became final in the second quarter of 2002. The royalty owners recently filed a new petition alleging that the class may properly be brought so long as ‘‘sub-class’’ groups are broken out. The Company is vigorously contesting this new petition.

A class action lawsuit titled *Gilbert H. Coulter, et al. v. Anadarko Petroleum Corporation* has been certified in the 26th Judicial District Court, Stevens County, Kansas. In this action, the royalty owners contend that royalty was underpaid as a result of the deduction for certain post-production costs in the calculation of royalty. The Company believes that its method of calculating royalty was proper and that its gas was marketable in the condition produced, and thus plaintiffs' claims are without merit. This case was certified as a class action in August 2000 and was tried in February 2002. It is uncertain when the trial court will render its ruling.

CITGO Litigation CITGO Petroleum Corporation's (CITGO) claims arise out of an Asset Purchase and Contribution Agreement in 1987 whereby Anadarko Holding's predecessor sold a refinery located in Corpus Christi, Texas to CITGO's predecessor. After the sale of the refinery, numerous individuals living near the refinery sued CITGO (the Neighborhood Litigation) thereby implicating the Asset Purchase and Contribution Agreement indemnity provision. CITGO and Anadarko Holding eventually entered into a settlement agreement to allocate, on an interim basis, each party's liability for defense and liability cost in that and related litigation. That agreement provides that once the Neighborhood Litigation and certain related claims are resolved, then the parties will determine their final indemnity obligations to each other through binding arbitration. At the present time, Anadarko Holding and CITGO have agreed to defer arbitrating the allocation of responsibility for this liability in order to focus their efforts on a global settlement. Arbitration will resume upon request of either CITGO or Anadarko Holding. In conjunction with this matter, Anadarko Holding sued Continental Insurance for denial of coverage for claims related to this dispute. Anadarko Holding and Continental Insurance settled the insurance coverage litigation which resulted in Continental Insurance paying a portion of Anadarko Holding's claims. Negotiations and discussions with CITGO continue. Anadarko Holding has offered to settle all outstanding issues for approximately $4 million and a liability for this amount has been accrued.

Kansas Ad Valorem Tax

General The Natural Gas Policy Act of 1978 allowed a "severance, production or similar" tax to be included as an add-on, over and above the maximum lawful price charged for natural gas. Based on the Federal Energy Regulatory Commission (FERC) ruling that the Kansas ad valorem tax was such a tax, the Company collected the Kansas ad valorem tax.

Background of PanEnergy Litigation FERC's ruling regarding the ability of producers to collect the Kansas ad valorem tax was appealed to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The Court held in June 1988 that FERC failed to provide a reasoned basis for its findings and remanded the case to FERC.

Ultimately, the D.C. Circuit issued a decision on August 2, 1996 ruling that producers must refund all Kansas ad valorem taxes collected relating to production since October 1983. The Company filed a petition for writ of certiorari with the Supreme Court. That petition was denied on May 12, 1997.

PanEnergy Litigation On May 13, 1997, the Company filed a lawsuit in the Federal District Court for the Southern District of Texas against PanEnergy seeking declaration that pursuant to prior agreements Anadarko is not required to issue refunds to PanEnergy for the principal amount of $14 million (before taxes) and, if the petition for adjustment is denied in its entirety by FERC with respect to PanEnergy refunds, interest in an amount of $38 million (before taxes). The Company also sought from PanEnergy the return of the $1 million (before taxes) charged against income in 1993 and 1994. In October 2000, the U.S. Magistrate issued recommendations concerning motions for summary judgment previously filed by both parties. In essence, the Magistrate's recommendation finds that the Company should be responsible for refunds attributable to the time period following August 1, 1985 while Duke Energy (as the successor company to Anadarko Production Company) should be responsible for refunds attributable to the time period before August 1, 1985.

The Company reached a settlement agreement with PanEnergy that required the Company to pay $15 million for settlement in full of all matters relating to the refunds of Kansas ad valorem tax reimbursements collected by the Company as first seller from August 1, 1985 through 1988. The settlement agreement was approved by FERC and paid by Anadarko during 2001. The settlement agreement does not have any impact on the outstanding dispute between the Company and PanEnergy in connection with the refunds that relate to the Cimmaron River System. Anadarko's net income for 2001 included a $15 million charge (before taxes) related to the settlement agreement. Discussions with the Kansas Corporation Commission and PanEnergy to reach a settlement of the Cimmaron River System dispute are ongoing. At this time, it is estimated that a resolution may be reached in the first quarter of 2003 that may result in payment of about $6 million by the Company. A provision was charged against income in 2001.

Other Litigation The Company has a reserve of about $2 million for Kansas ad valorem tax refunds. This amount reflects all principal and interest that may be due at the conclusion of all regulatory proceedings and litigation to parties other than PanEnergy.

Other The Company is subject to other legal proceedings, claims and liabilities which arise in the ordinary course of its business. In the opinion of the Company, the liability with respect to these actions will not have a material effect on the Company.

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders during the fourth quarter of 2002.

Executive Officers of the Registrant

Name	Age at End of 2003	Position
Robert J. Allison, Jr.	64	Chairman of the Board
John N. Seitz	52	President and Chief Executive Officer
Charles G. Manley	59	Executive Vice President, Administration
Michael E. Rose	56	Executive Vice President and Chief Financial Officer
William D. Sullivan	47	Executive Vice President, Exploration and Production
Rex Alman III	52	Senior Vice President, Algeria
Michael D. Cochran	61	Senior Vice President, Strategy and Planning
James R. Larson	53	Senior Vice President, Finance
Richard J. Sharples	56	Senior Vice President, Marketing and Minerals
Bruce H. Stover	54	Senior Vice President, Worldwide Business Development
Robert P. Daniels	44	Vice President, Canada
Diane L. Dickey	47	Vice President and Controller
James J. Emme	47	Vice President, Exploration
Morris L. Helbach	58	Vice President, Information Technology Services and Chief Information Officer
Richard A. Lewis	59	Vice President, Human Resources
J. Anthony Meyer	45	Vice President, International and Alaska Operations
Mark L. Pease	47	Vice President, Domestic Operations
Gregory M. Pensabene	53	Vice President, Government Relations and Public Affairs
Albert L. Richey	54	Vice President and Treasurer
Charlene A. Ripley	39	Vice President
Suzanne Suter	57	Vice President, Corporate Secretary, Chief Governance Officer and Interim General Counsel
A. Paul Taylor, Jr.	54	Vice President, Investor Relations
Donald R. Willis	53	Vice President, Corporate Services

Mr. Allison relinquished the role of Chief Executive Officer in 2002 and remains Chairman of the Board. He was named Chairman of the Board and Chief Executive Officer effective October 1986. He has worked for the Company since 1973.

Mr. Seitz was named President and Chief Executive Officer in 2002. He was named President and Chief Operating Officer in 1999. He was named Executive Vice President, Exploration and Production and a member of the Company's Board of Directors during 1997. Prior to that, Mr. Seitz served as Senior Vice President, Exploration since 1995. He has worked for the Company since 1977.

Mr. Manley was named Executive Vice President, Administration in 2000. Prior to this position, he served as Senior Vice President, Administration since 1993. He has worked for the Company since 1974.

Mr. Rose was named Executive Vice President and Chief Financial Officer in 2000. Prior to this position, he served as Senior Vice President, Finance and Chief Financial Officer since 1993. He has worked for the Company since 1978.

Mr. Sullivan was named Executive Vice President, Exploration and Production in 2001. Prior to this position, he served as Vice President, Operations — International, Gulf of Mexico and Alaska since 2000, Vice President, International Operations since 1998 and Vice President, Algeria since 1995. He has worked for the Company since 1981.

Mr. Alman was named Senior Vice President, Algeria in 2002 and he was named Senior Vice President, Domestic Operations in 2001. Prior to this position, he served as Vice President, Domestic Operations since 1997. He has worked for the Company since 1976.

Dr. Cochran was named Senior Vice President, Strategy and Planning in 2001. Prior to this position, he served as Vice President, Exploration since 1997. He has worked for the Company since 1987.

Mr. Larson was named Senior Vice President, Finance in 2002. Prior to this position, he served as Vice President and Controller since 1995. He has worked for the Company since 1983.

Mr. Sharples was named Senior Vice President, Marketing and Minerals in 2001. Prior to this position, he served as Vice President, Marketing since he joined the Company in 1993.

Mr. Stover was named Senior Vice President, Worldwide Business Development in 2001. Prior to this position, he served as Vice President, Worldwide Business Development since 1998 and Vice President, Acquisitions since 1993. He has worked for the Company since 1980.

Mr. Daniels was named Vice President, Canada in 2001. Prior to this position, he served in various managerial roles in the Exploration Department for Anadarko Algeria Company LLC. He has worked for the Company since 1985.

Ms. Dickey was named Vice President and Controller in 2002. Prior to this position, she served as Assistant Controller since 1995. She has worked for the Company since 1978.

Mr. Emme was named Vice President, Exploration in 2001 and named Vice President, Canada in 2000. Prior to this he served in various managerial roles in the Exploration Department. Mr. Emme has worked for the Company since 1981.

Mr. Helbach joined Anadarko in 2000 as Vice President, Information Technology Services and Chief Information Officer. Prior to joining Anadarko, he was General Manager and Chief Information Officer at Conoco, Inc.

Mr. Lewis was named Vice President, Human Resources in 1995. He joined the Company as Manager Human Resources in 1985.

Mr. Meyer was named Vice President, International and Alaska Operations in 2002 and was named Vice President, Algeria in 2001. Prior to this position, he served as President and General Manager, Anadarko Algeria Company, LLC and in other managerial roles for Anadarko Algeria Company, LLC and in the Operations Department. He has worked for the Company since 1981.

Mr. Pease was named Vice President, Domestic Operations in 2002. Prior to this position, he served as Vice President, International and Alaska Operations since September 2001, Vice President, Engineering and Technology since February 2001, Vice President, Algeria since 1998 and as President and General Manager, Anadarko Algeria Company, LLC since 1993. He has worked for the Company since 1979.

Mr. Pensabene joined Anadarko in 1997 as Vice President, Government Relations. Prior to joining Anadarko, he was a partner in the law firm of Muys & Pensabene from 1996 to 1997.

Mr. Richey was named Vice President and Treasurer in 1995. He joined the Company as Treasurer in 1987.

Ms. Ripley was named Vice President in 2003. Prior to this position, she served as Vice President, General Counsel and Secretary of Anadarko Canada Corporation and its predecessor since 1998. She has worked for the Company since 1997.

Ms. Suter was named Vice President, Corporate Secretary and Chief Governance Officer in 2002 and in January 2003 she was given the additional position of Interim General Counsel. She has served as Associate General Counsel since 2001 and Corporate Secretary since 1987. She has worked for the Company since 1986.

Mr. Taylor was named Vice President, Investor Relations in 1999. Prior to this position, he served as Vice President, Corporate Communications since 1987. He has worked for the Company since 1986.

Mr. Willis was named Vice President, Corporate Services in 2000. Prior to this position, he served as Manager, Corporate Administration. He has worked for the Company since 1979.

All officers of Anadarko are elected in April of each year at an organizational meeting of the Board of Directors to hold office until their successors are duly elected and shall have qualified. There are no family relationships between any directors or executive officers of Anadarko.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

Information on the market price and cash dividends declared per share of common stock is included in the *Stockholder Information* in the Anadarko Petroleum Corporation 2002 Annual Report (Annual Report) which is incorporated herein by reference.

As of February 24, 2003, there were approximately 22,000 direct holders of Anadarko common stock. The following table sets forth the amount of dividends paid on Anadarko common stock during the two years ended December 31, 2002.

millions	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2002	**$ 18**	**$ 18**	**$ 20**	**$ 24**
2001	$ 12	$ 13	$ 12	$ 20

The amount of future common stock dividends will depend on earnings, financial condition, capital requirements and other factors, and will be determined by the Directors on a quarterly basis. For additional information, see *Dividends* under Item 7 of this Form 10-K.

Equity Compensation Plan Table The following table sets forth information with respect to the equity compensation plans available to directors, officers and employees of the Company as of December 31, 2002:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders	15,328,369	$42.68	2,498,391
Equity compensation plans not approved by security holders	—	—	—
Total	15,328,369	$42.68	2,498,391

Unregistered Securities In March 2001, Anadarko issued $650 million of Zero Yield Puttable Contingent Debt Securities (ZYP-CODES) due 2021 to qualified institutional buyers under Rule 144A and non-U.S. persons under Regulation S. The initial purchaser of the ZYP-CODES was Lehman Brothers Inc. The ZYP-CODES were subsequently registered on a Form S-3 effective in July 2001.

In April 2001, Anadarko Finance Company, a wholly-owned finance subsidiary of Anadarko, issued $1.3 billion in notes to qualified institutional buyers under Rule 144A and non-U.S. persons under Regulation S. The initial purchaser was Credit Suisse First Boston Corporation. The notes were subsequently registered on a Form S-4 effective in July 2001.

For additional information, see *Note 7 — Debt* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Item 6. Selected Financial Data

See *Five Year Financial Highlights* in the Annual Report, which is incorporated herein by reference.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Financial Results

Selected Financial Data

millions except per share amounts	**2002**	2001	2000
Revenues	**$3,860**	$4,718	$2,911
Costs and expenses	**2,435**	5,081	1,559
Interest expense	**203**	92	93
Other (income) expense	**15**	(65)	(167)
Net income (loss) available to common stockholders before cumulative effect of change in accounting principle	**$ 825**	$ (183)	$ 813
Net income (loss) available to common stockholders	**$ 825**	$ (188)	$ 796
Earnings (loss) per share — before cumulative effect of change in accounting principle — basic	**$ 3.32**	$ (0.73)	$ 4.42
Earnings (loss) per share — before cumulative effect of change in accounting principle — diluted	**$ 3.21**	$ (0.73)	$ 4.25
Earnings (loss) per share — basic	**$ 3.32**	$ (0.75)	$ 4.32
Earnings (loss) per share — diluted	**$ 3.21**	$ (0.75)	$ 4.16

Net Income Anadarko's net income available to common stockholders for 2002 totaled $825 million, or $3.21 per share (diluted), compared to net loss available to common stockholders for 2001 of $188 million, or $0.75 per share (diluted). Net loss for 2001 includes non-cash charges of $2.5 billion ($1.6 billion after taxes) for impairments of the carrying value of oil and gas properties primarily in the United States, Canada and Argentina as a result of low natural gas and oil prices at the end of the third quarter of 2001. See *Critical Accounting Policies.* Anadarko had net income available to common stockholders in 2000 of $796 million or $4.16 per share (diluted).

In January 2002, the Company discontinued the amortization of goodwill in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets." See *Note 3 — Goodwill* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Revenues

millions	**2002**	2001	2000
Gas sales	**$1,835**	$2,952	$1,615
Oil and condensate sales	**1,690**	1,397	946
Natural gas liquids sales	**222**	256	264
Other sales	**113**	113	86
Total	**$3,860**	$4,718	$2,911

During 2002, the Company adopted Emerging Issues Task Force (EITF) Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." In accordance with EITF Issue No. 02-3, marketing sales and purchases resulting in physical settlement for prior periods have been reclassified to show net marketing margins as revenues. The marketing margins related to the Company's equity production are included in gas sales, oil and condensate sales and natural gas liquids (NGLs) sales and are reflected in commodity prices. The marketing margin related to purchases of third-party commodities is included in other sales. This reclassification had no effect on reported net income or cash flow.

Anadarko's total revenues for 2002 were down $858 million or 18% compared to total revenues in 2001 due primarily to a significant decrease in natural gas prices, as well as decreases in natural gas volumes, partially offset by higher crude oil prices and volumes.

Total revenues for 2001 increased $1.8 billion or 62% compared to 2000 due primarily to a significant increase in sales volumes, partially offset by a decrease in crude oil, condensate and NGLs prices.

Analysis of Oil and Gas Sales Volumes

	2002	2001	2000
Barrels of Oil Equivalent (MMBOE)			
United States	**130**	144	83
Canada	**35**	34	12
Algeria	**24**	8	10
Other International	**8**	13	7
Total	**197**	199	112
Barrels of Oil Equivalent per Day (MBOE/d)			
United States	**355**	394	226
Canada	**97**	93	34
Algeria	**65**	22	26
Other International	**22**	37	20
Total	**539**	546	306

MMBOE — million barrels of oil equivalent
MBOE/d — thousand barrels of oil equivalent per day

During 2002, Anadarko sold 197 MMBOE, a decrease of 2 MMBOE or 1% compared to sales of 199 MMBOE in 2001. The decrease in volumes for 2002 was primarily due to a decrease of 14 MMBOE due to operations in the United States, primarily offshore, and in Texas and Louisiana, and a decrease of 4 MMBOE related to the disposition of operations in Guatemala and Argentina in 2001. The decrease in volumes in the United States was primarily a result of natural production declines and a decrease in development drilling in late 2001 and early 2002 in response to lower commodity prices. These decreases were offset by an increase of 16 MMBOE in Algeria due to the expansion of production facilities. The Company's sales volumes were up 87 MMBOE or 78% in 2001 compared to 112 MMBOE in 2000. Approximately 70% of the increase in volumes during 2001 was due to a full year of operations in 2001 from properties acquired with the Anadarko Holding Company (Anadarko Holding) merger transaction in July 2000, compared to 5½ months of operations in 2000. The remainder of the increase in volumes during 2001 was due primarily to increases of approximately 13 MMBOE from operations in the Gulf of Mexico, 7 MMBOE related to the acquisition of Berkley Petroleum Corp. (Berkley) in March 2001, 6 MMBOE from operations in the Bossier play in Texas and Louisiana and 5 MMBOE from operations in Alaska. Sales volumes represent actual production volumes adjusted for changes in commodity inventories. Anadarko employs marketing strategies to help manage volumes and mitigate the effect of price volatility, which is likely to continue in the future. See *Derivative Instruments* under Item 7a of this Form 10-K.

Natural Gas Sales Volumes and Average Prices

	2002	2001	2000
United States (Bcf)	**507**	573	338
MMcf/d	**1,390**	1,569	922
Price per Mcf	**$ 2.84**	$ 4.23	$4.22
Canada (Bcf)	**135**	121	46
MMcf/d	**370**	331	127
Price per Mcf	**$ 2.93**	$ 4.38	$4.09
Other International (Bcf)	**—**	1	1
MMcf/d	**—**	4	3
Price per Mcf	**$ —**	$ 1.22	$1.08
Total (Bcf)	**642**	695	385
MMcf/d	**1,760**	1,904	1,052
Price per Mcf	**$ 2.86**	$ 4.25	$4.19

Bcf — billion cubic feet
Mcf — thousand cubic feet
MMcf/d — million cubic feet per day

Anadarko's natural gas sales volumes in 2002 were down 53 Bcf or 8% compared to 2001. The decrease in volumes was due primarily to a decrease of 66 Bcf from operations within the United States, primarily offshore and in Texas, partially offset by an increase of 14 Bcf from operations in Canada primarily due to the Berkley acquisition in 2001. The Company's natural gas sales volumes for 2001 were up 310 Bcf or 81% compared to 2000. Approximately 70% of the increase in natural gas volumes during 2001 was due to a full year of production in 2001 from properties acquired with the Anadarko Holding merger transaction compared to 5½ months of production in 2000. The remainder of the increase in volumes during 2001 was due primarily to increases of approximately 44 Bcf from operations in the Gulf of Mexico, 34 Bcf from the Bossier play in Texas and Louisiana and 29 Bcf related to the acquisition of Berkley in March 2001. Production of natural gas is generally not directly affected by seasonal swings in demand. However, the Company may decide during periods of low commodity prices to decrease development activity, which can result in decreased production volumes.

The Company's average natural gas price in 2002 decreased 33% compared to 2001. The decrease in prices during 2002 were attributed to a severe decline in natural gas demand as a result of high prices in early 2001, followed by a national economic downturn and mild summer weather in 2001. The Company's average natural gas price in 2001 was essentially flat compared to 2000. The higher natural gas prices realized in the first half of 2001 were offset by a decrease in natural gas prices in the second half of 2001. As of the end of January 2003, the Company had hedged 38% and 22% of the Company's natural gas production that is expected to be produced during 2003 and 2004, respectively. As a result, the remaining future natural gas volumes are subject to continued volatility based on fluctuations in market prices. See *Derivative Instruments* under Item 7a of this Form 10-K.

Quarterly Natural Gas Sales Volumes and Average Prices

	2002	2001	2000
First Quarter			
Bcf	**162**	164	44
MMcf/d	**1,805**	1,822	486
Price per Mcf	**$ 2.26**	$ 6.89	$ 2.63
Second Quarter			
Bcf	**163**	184	49
MMcf/d	**1,791**	2,018	536
Price per Mcf	**$ 3.05**	$ 4.58	$ 3.39
Third Quarter			
Bcf	**162**	176	138
MMcf/d	**1,764**	1,913	1,498
Price per Mcf	**$ 2.64**	$ 3.00	$ 3.86
Fourth Quarter			
Bcf	**155**	171	154
MMcf/d	**1,682**	1,863	1,676
Price per Mcf	**$ 3.50**	$ 2.63	$ 5.19

Crude Oil and Condensate Sales Volumes and Average Prices

	2002	2001	2000
United States (MMBbls)	**31**	34	15
MBbls/d	**85**	93	40
Price per barrel	**$23.07**	$23.08	$28.59
Canada (MMBbls)	**12**	13	4
MBbls/d	**33**	35	12
Price per barrel	**$19.31**	$18.18	$27.33
Algeria (MMBbls)	**24**	8	10
MBbls/d	**65**	22	26
Price per barrel	**$24.38**	$23.97	$28.73
Other International (MMBbls)	**8**	13	7
MBbls/d	**22**	36	20
Price per barrel	**$19.92**	$14.35	$18.35
Total (MMBbls)	**75**	68	36
MBbls/d	**205**	186	98
Price per barrel	**$22.55**	$20.56	$26.42

MMBbls — million barrels
MBbls/d — thousand barrels per day

Anadarko's crude oil and condensate sales volumes for 2002 increased 7 MMBbls or 10% compared to 2001. The increase was due primarily to an increase of approximately 16 MMBbls from operations in Algeria primarily due to the expansion of production facilities and an increase of 2 MMBbls due to the acquisition of producing properties in Qatar in 2001. These increases were partially offset by a decrease of 4 MMBbls related primarily to the sale of producing properties in Guatemala and Argentina in 2001, a decrease of 3 MMBbls related to operations in the United States, primarily offshore, and a decrease of 3 MMBbls related to operations in Venezuela primarily due to higher oil prices. See *Critical Accounting Policies*.

Crude oil and condensate sales volumes in 2001 increased 32 MMBbls or 89% compared to 2000. Approximately 65% of the increase in sales volumes during 2001 was due to a full year of operations in 2001 from properties acquired with the Anadarko Holding merger transaction compared to 5½ months of operations in 2000. The remainder of the increase in crude oil and condensate sales volumes during 2001 was due primarily to increases of approximately 6 MMBbls from operations in the Gulf of Mexico, 5 MMBbls in Alaska and 2 MMBbls related to the acquisition of Berkley in March 2001. Production of oil usually is not affected by seasonal swings in demand or in market prices.

The Company's average realized crude oil price in 2002 increased 10% compared to 2001. The increase in crude oil prices in 2002 was due primarily to continued uncertainty of the situation in the middle east, the oil workers strike in Venezuela and a colder than normal winter late in 2002 which increased oil demand in the United States. Anadarko's average realized crude oil prices for 2001 decreased 22% compared to 2000. The decrease in crude oil prices during 2001 is attributed primarily to a modest increase in supply and very slow growth in demand due to a worldwide economic downturn and a sharp decline in jet fuel consumption. As of the end of January 2003, the Company had hedged 35% and 3% of the Company's crude oil production that is expected to be produced during 2003 and 2004, respectively. As a result, the remaining future oil and condensate volumes are subject to continued volatility based on fluctuations in market prices.

Quarterly Crude Oil and Condensate Sales Volumes and Average Prices

	2002	2001	2000
First Quarter			
MMBbls	**19**	17	4
MBbls/d	**212**	186	49
Price per barrel	**$18.54**	$21.92	$26.36
Second Quarter			
MMBbls	**19**	18	3
MBbls/d	**205**	192	38
Price per barrel	**$22.57**	$21.61	$26.99
Third Quarter			
MMBbls	**18**	18	13
MBbls/d	**191**	192	141
Price per barrel	**$24.50**	$21.82	$27.53
Fourth Quarter			
MMBbls	**20**	16	15
MBbls/d	**214**	175	161
Price per barrel	**$24.67**	$16.64	$25.33

Natural Gas Liquids Sales Volumes and Average Prices

	2002	2001	2000
Total (MMBbls)	**15**	15	12
MBbls/d	**41**	42	33
Price per barrel	**$14.80**	$16.55	$21.70

The Company's NGLs sales volumes in 2002 were essentially flat compared to 2001. NGLs sales volumes in 2001 increased 25% compared to 2000 primarily due to the increase in natural gas sales volumes. The 2002 average NGLs prices decreased 11% compared to 2001. High levels of NGLs inventories in the United States during the first half of 2002, coupled with lower demand for NGLs by the petrochemical industry, have caused NGLs prices to decline. The 2001 average NGLs prices decreased 24% compared to 2000 due primarily to a decrease in demand. NGLs production is dependent on natural gas prices and the economics of processing the natural gas volumes to extract NGLs.

Costs and Expenses

millions	**2002**	2001	2000
Operating expenses	**$ 747**	$ 769	$ 487
Administrative and general	**314**	292	270
Depreciation, depletion and amortization	**1,121**	1,154	593
Other taxes	**214**	247	128
Impairments related to oil and gas properties	**39**	2,546	50
Amortization of goodwill	**—**	73	31
Total	**$2,435**	$5,081	$1,559

During 2002, Anadarko's costs and expenses decreased $2.6 billion or 52% compared to 2001 due to the following factors:

— Operating expenses decreased $22 million (3%) primarily due to a decrease in costs associated with processing NGLs.

— Administrative and general expenses increased $22 million (8%). An increase of $58 million due primarily to increases in benefits and salaries expenses associated with the Company's growing workforce was partially offset by a $31 million decrease in merger related expenses and a $5 million decrease related to an adjustment to provisions for doubtful accounts.

— Depreciation, depletion and amortization (DD&A) expense decreased $33 million (3%). The decrease is due primarily to a lower DD&A rate for oil and gas properties in 2002 as a result of ceiling test impairments in the third quarter of 2001 and a decrease related to slightly lower production volumes in 2002.

— Other taxes decreased $33 million (13%). The decrease is primarily due to a decrease in production taxes as a result of lower commodity prices and slightly lower production volumes in 2002.

— Impairments in 2002 relate primarily to oil and gas properties in Congo ($16 million), Oman ($10 million), Australia ($7 million) and Tunisia ($5 million) primarily due to unsuccessful exploration activities.

— Amortization of goodwill was discontinued in 2002 in accordance with SFAS No. 142.

During 2001, Anadarko's costs and expenses increased $3.5 billion or 226% compared to 2000 due to the following factors:

— Operating expenses increased $282 million (58%) primarily due to a significant increase in the number of producing wells as a result of mergers and acquisitions in 2000 and 2001 and significant development activity in the Gulf of Mexico, Alaska and the Bossier play in east Texas and Louisiana. Operating expenses were also impacted by an increase in oil field service costs.

— Administrative and general expenses increased $22 million (8%). An increase of $67 million due primarily to the Company's expanded workforce resulting from the Anadarko Holding merger transaction in mid-2000 and higher costs associated with the Company's growing workforce was partially offset by a decrease in provisions for doubtful accounts of $23 million and a $22 million decrease in merger related expenses.

— DD&A expense increased $561 million (95%). About 80% of the increase was due to the increase in volumes as a result of mergers and acquisitions in 2000 and 2001 and significant development activity. The remaining increase is due to increases in the DD&A rate, which is also due to the merger and acquisitions.

— Other taxes increased $119 million (93%). Approximately 50% of the increase was due to an increase in ad valorem taxes as a result of the significant increase in properties as a result of the merger and acquisitions. The remainder of the increase is primarily due to an increase in production taxes as a result of the increase in volumes.

— Impairments in 2001 were due to low oil and gas prices at the end of the third quarter of 2001, which resulted in ceiling test impairments for the United States ($1.7 billion), Canada ($808 million), Argentina ($15 million) and Brazil ($4 million), as well as unsuccessful exploration activities in the United Kingdom ($11 million) and Ghana ($7 million).

— Amortization of goodwill increased $42 million due to the Anadarko Holding merger transaction in mid-2000 ($32 million) and the Berkley acquisition in 2001 ($10 million).

Interest Expense

millions	**2002**	2001	2000
Gross interest expense	**$ 358**	$ 301	$ 193
Capitalized interest	**(155)**	(209)	(100)
Net interest expense	**$ 203**	$ 92	$ 93

Anadarko's gross interest expense has increased over the past three years due primarily to the Anadarko Holding merger transaction in mid-2000 and the Berkley acquisition in 2001 as well as higher levels of borrowings for capital expenditures, including producing property acquisitions. Gross interest expense in 2002 increased 19% compared to 2001 primarily due to higher average debt outstanding in 2002 primarily because of acquisitions in 2001 and slightly higher interest rates. Gross interest expense in 2001 increased 56% compared to 2000 primarily due to the Anadarko Holding merger transaction in mid-2000 and the Berkley acquisition in 2001 which resulted in higher average borrowings during 2001. See *Capital Resources and Liquidity* and *Outlook on Liquidity.*

In 2002, capitalized interest decreased by 26% compared to 2001 primarily due to a decrease in capitalized costs that qualify for interest capitalization. In 2001, capitalized interest increased by 109% compared to 2000 primarily due to an increase in costs that qualify for interest capitalization related to the Anadarko Holding merger transaction in mid-2000 and the Berkley acquisition in 2001. For additional information about the Company's policies regarding costs excluded and capitalized interest see *Critical Accounting Policies — Costs Excluded* and *Capitalized Interest.*

Other (Income) Expense

millions	**2002**	2001	2000
Firm transportation keep-whole contract valuation	**$(35)**	$(91)	$(175)
Unrealized (gain) loss on derivative instruments	**33**	(18)	—
Gas sales contracts — accretion of discount	**11**	14	—
Foreign currency exchange	**1**	29	7
Other	**5**	1	1
Total	**$ 15**	$(65)	$(167)

Other income in 2002 decreased $80 million compared to 2001 due primarily to a $56 million decrease in income related to the effect of lower market values for firm transportation subject to a keep-whole agreement and a $51 million decrease related to unrealized (gain) loss on derivative instruments due to increased commodity prices and hedging activity, partially offset by a $28 million decrease in foreign currency exchange losses primarily due to the restructuring of Canadian debt and changes in the Canadian exchange rate. Other income in 2001 decreased $102 million compared to the same period of 2000 due primarily to an $84 million decrease related to the effect of significantly lower market value for firm transportation subject to a keep-whole agreement and a $22 million increase in foreign currency exchange losses primarily due to changes in the Canadian exchange rates. See *Derivative Instruments* and *Foreign Currency Risk* under Item 7a of this Form 10-K.

Income Tax Expense (Benefit)

millions	**2002**	2001	2000
Income tax expense (benefit)	**$376**	$(214)	$602

For 2002, income taxes increased $590 million compared to 2001. Income taxes for 2001 decreased $816 million compared to 2000. Income taxes for 2001 include a benefit of approximately $962 million related to the impairment of the carrying value of oil and gas properties in the United States, Canada and Argentina as a result of low natural gas and crude oil prices at the end of the third quarter of 2001.

Excluding the effect of the impairment and related tax benefit in 2001, income taxes for 2002 decreased primarily due to the decrease in earnings before income taxes. Excluding the effect of the impairment and the related tax benefit in 2001, the increase in 2001 income taxes compared to 2000 was primarily due to the increase in earnings before income taxes.

The effective tax rate for 2002, 2001 and 2000 was 31%, 55% and 42%, respectively. The variances in the effective tax rate for 2002 and 2000 from the statutory rate of 35% were due primarily to changes in income taxes related to foreign operations. The effective tax rate for 2001 was 35%, excluding the effect of the impairment and the related tax benefit.

Marketing Strategies

Overview The Company's sales of natural gas, crude oil, condensate and NGLs are generally made at the market prices of those products at the time of sale. Therefore, even though the Company sells significant volumes to major purchasers, the Company believes other purchasers would be willing to buy the Company's natural gas, crude oil, condensate and NGLs at comparable market prices. The Company's marketing department actively manages sales of its oil and gas through Anadarko Energy Services Company (AES), Anadarko, Anadarko Canada Corporation and Anadarko Holding. The Company markets its production to customers at competitive prices, maximizing realized prices while managing credit exposure. The market knowledge gained through the marketing effort is valuable to the corporate decision making process.

The Company also conducts trading activities for the purpose of generating profits on or from exposure to changes in market prices of gas, oil, condensate and NGLs. However, the Company does not engage in market-making practices nor does it trade in any non-energy-related commodities. The Company's trading risk position, typically, is a net short position that is offset by the Company's natural long position as a producer. The Company's marketing function does not engage in round-trip trades or participate in any marketing-related partnerships. Essentially all of the Company's trading transactions have a term of less than one year and most are less than three months. See *Derivative Instruments* under Item 7a of this Form 10-K.

During 2002, all segments of the natural gas market experienced increased scrutiny of their financial condition, liquidity and credit. This has been reflected in rating agency credit downgrades of many merchant energy trading companies. In 2002, Anadarko has not experienced any material financial losses associated with credit deterioration of third-party gas purchasers; however, in certain situations the Company has declined to transact with some counterparties and changed its sales terms to require some counterparties to pay in advance or post letters of credit.

Natural Gas The North American natural gas market has grown significantly throughout the last 10 years and management believes continued growth to be likely. Natural gas prices have been extremely volatile and are expected to continue to be so. Management believes the Company's portfolio of exploration and development prospects should position Anadarko to continue to participate in this growth. AES is a full-service marketing company offering supply assurance, competitive pricing, risk management services and other services tailored to its customers' needs. Approximately 40% of the Company's gas production was sold through AES in 2002. The Company also purchases some physical volumes for resale primarily from partners and producers near Anadarko's production. These purchases allow the Company to aggregate larger volumes of gas and attract larger, creditworthy customers, which in turn enhances the value of the Company's production. The Company sells natural gas under a variety of contracts and may also receive a service fee related to the level of reliability and service required by the customer. The Company has the marketing capability to move large volumes of gas into and out of the "daily" gas market to take advantage of any price volatility. Included in this strategy is the use of leased natural gas storage facilities and various derivative instruments.

Anadarko Holding was a party to several long-term firm gas transportation agreements that supported the gas marketing program within the gathering, processing and marketing (GPM) business segment, which was sold in 1999 to Duke Energy (Duke). Most of the GPM's firm long-term transportation contracts were transferred to Duke in the GPM disposition. One contract was retained, but is managed and operated by Duke. Anadarko is not responsible for the operations of the contracts and does not utilize the associated transportation assets to transport the Company's natural gas. As part of the GPM disposition, Anadarko Holding agreed to pay Duke if transportation market values fall below the fixed contract transportation rates, while Duke will pay Anadarko Holding if the transportation market values exceed the contract transportation rates (keep-whole agreement). The fair value of the short-term portion of the firm transportation keep-whole agreement is calculated with actively quoted natural gas basis prices. Basis is the difference in value between gas at various delivery points and the

New York Mercantile Exchange (NYMEX) gas futures contract price. Management believes that natural gas basis price quotes beyond the next twelve months are not reliable indicators of fair value due to decreasing liquidity. Accordingly, the fair value of the long-term portion is estimated based on historical natural gas basis prices, discounted at 10% per year. Management also periodically evaluates the supply and demand factors (such as expected drilling activity, anticipated pipeline construction projects, expected changes in demand at pipeline delivery points) that may impact the future market value of the firm transportation capacity to determine if the estimated fair value should be adjusted.

In 2002, 2001 and 2000, approximately 29%, 31% and 56%, respectively, of the Company's gas production was sold under long-term contracts to Duke. These sales represent 13%, 21% and 24%, respectively, of total revenues in 2002, 2001 and 2000. Most of the Company's gas production sold to Duke is under a single agreement that expires at the end of the first quarter of 2004. Volumes sold to Duke under this contract may be delivered at a number of locations generally at the tailgate of processing facilities owned or operated by Duke or its affiliates and typically in the general vicinity of the fields where produced. The pricing of gas under this contract is market based and therefore varies monthly and by region.

Crude Oil, Condensate and NGLs Anadarko's crude oil, condensate and NGLs revenues are derived from production in the U.S., Canada, Algeria and other international areas. Most of the Company's U.S. crude oil and NGLs production is sold under 30-day "evergreen" contracts with prices based on marketing indices and adjusted for location, quality and transportation. Most of the Company's Canadian oil production is sold on a term basis of one year or greater. Oil from Algeria is sold by tanker as Saharan Blend to customers primarily in the Mediterranean area. Saharan Blend is a high quality crude that provides refiners with large quantities of premium products like high quality jet and diesel fuel. AES purchases and sells third-party crude oil, condensate and NGLs in the Company's domestic and international market areas. Included in this strategy is the use of various derivative instruments.

Gas Gathering Systems and Processing Anadarko's investment in gas gathering operations allows the Company to better manage its gas production, improve ultimate recovery of reserves, enhance the value of gas production and expand marketing opportunities. The Company has invested $162 million to build or acquire gas gathering systems over the last five years. The vast majority of the gas flowing through these systems is from Anadarko operated wells.

The Company processes gas at various third-party plants under agreements generally structured to provide for the extraction and sale of NGLs in efficient plants with flexible commitments. Anadarko also processes gas and has interests in one operated plant and three non-operated plants. Anadarko's strategy to aggregate gas through Company-owned and third-party gathering systems allows Anadarko to secure processing arrangements in each of the regions where the Company has significant production.

Marketing Contracts The following schedules provide additional information regarding the Company's marketing and trading portfolio of physical and derivative contracts and the firm transportation keep-whole agreement and related derivatives as of December 31, 2002. The Company records income or loss on these activities using the mark-to-market method. See *Critical Accounting Policies* for an explanation of how the fair value for derivatives are calculated.

millions	**Marketing and Trading**	**Firm Transportation Keep-whole**	**Total**
Fair value of contracts outstanding as of December 31, 2001	$17	$(82)	$(65)
Contracts realized or otherwise settled during 2002	15	(26)	(11)
Fair value of new contracts when entered into during 2002	7	—	7
Other changes in fair value	(44)	35	(9)
Fair value of contracts outstanding as of December 31, 2002	$ (5)	$(73)	$(78)

Assets (Liabilities) *millions*	Maturity less than 1 year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess of 5 Years	Total
	Fair Value of Contracts as of December 31, 2002				
Marketing and Trading					
Prices actively quoted	$ (4)	$ —	$ —	$ —	$ (4)
Prices based on models and other valuation methods	(1)	—	—	—	(1)
Firm Transportation Keep-whole					
Prices actively quoted	$ (5)	$ —	$ —	$ —	$ (5)
Prices based on models and other valuation methods	—	(40)	(23)	(5)	(68)
Total					
Prices actively quoted	$ (9)	$ —	$ —	$ —	$ (9)
Prices based on models and other valuation methods	(1)	(40)	(23)	(5)	(69)

Operating Results

Drilling Activity During 2002, Anadarko participated in a total of 949 gross wells, including 686 gas wells, 217 oil wells and 46 dry holes. This compares to 1,420 gross wells (970 gas wells, 375 oil wells and 75 dry holes) in 2001 and 709 gross wells (385 gas wells, 269 oil wells and 55 dry holes) in 2000. The decrease in activity during 2002 reflects the Company's reduced spending for development drilling in response to lower commodity prices in late 2001 and early 2002. The increase in activity during 2001 was a result of mergers and acquisitions in 2001 and 2000 and improved commodity prices at the beginning of 2001.

The Company's 2002 exploration and development drilling program is discussed in *Oil and Gas Properties and Activities* under Item 1 of this Form 10-K.

Drilling Program Activity

	Gas	Oil	Dry	Total
2002 Exploratory				
Gross	**58**	**24**	**32**	**114**
Net	**45.2**	**19.9**	**25.3**	**90.4**
2002 Development				
Gross	**628**	**193**	**14**	**835**
Net	**444.2**	**147.6**	**10.7**	**602.5**
2001 Exploratory				
Gross	47	35	40	122
Net	35.6	26.0	27.0	88.6
2001 Development				
Gross	923	340	35	1,298
Net	677.5	262.5	26.6	966.6

Gross: total wells in which there was participation.
Net: working interest ownership.

Reserve Replacement Drilling activity is not the best measure of success for an exploration and production company. Anadarko focuses on growth, and profitability. Reserve replacement is the key to growth, and future profitability depends on the cost of finding oil and gas reserves, among other factors. For the 21st consecutive year, Anadarko more than replaced annual production volumes with proved reserves of natural gas, crude oil, condensate and NGLs, stated on a barrel of oil equivalent (BOE) basis.

During 2002, Anadarko's worldwide reserve replacement was 112% of total production of 196 MMBOE. The Company's worldwide reserve replacement in 2001 was 221% of total production of 201 MMBOE. The Company's worldwide reserve replacement in 2000 was 1,059% of total production of 112 MMBOE. Over the last five years, the Company's annual reserve replacement has averaged 368% of annual production volumes.

Excluding mergers, acquisitions and divestitures, Anadarko's worldwide reserve replacement for 2002 was 87% of total production compared to 173% for 2001 and 231% for 2000. The decrease in 2002 was partially due to a downward price revision of 36 MMBOE in Venezuela. See *Critical Accounting Policies.* Excluding mergers, acquisitions and divestitures, the Company's annual worldwide reserve replacement over the past five years averaged 187% of annual production volumes.

Anadarko continues to increase its energy reserves in the U.S. In 2002, the Company replaced 185% of its U.S. production volumes with U.S. reserves. This compares to a U.S. reserve replacement of 161% in 2001 and 855% in 2000. The Company's U.S. reserve replacement for the five-year period 1998-2002 was 325% of production. Excluding mergers, acquisitions and divestitures, Anadarko's U.S. reserve replacement for 2002, 2001 and 2000 was 137%, 160% and 207%, respectively, of total production. The Company's U.S. reserve replacement for the five-year period 1998-2002 was 179% excluding mergers, acquisitions and divestitures. By comparison, the most recent published U.S. industry average (1997-2001) was 111% (Source: U.S. Department of Energy). Anadarko's U.S. reserve replacement performance for the same period of 1997-2001 was 360% of production or 195% of production, excluding mergers, acquisitions and divestitures. Industry data for 2002 are not yet available.

Cost of Finding Cost of finding represents the cost of proved reserves added during a specific period through all means, including all costs and reserve additions related to extensions and discoveries, revisions, improved recovery and purchases of proved reserves. Cost of finding results in any one year can be misleading due to the long lead times associated with exploration and development. A better measure of cost of finding performance is over a five-year period.

For the period 1998-2002, Anadarko's worldwide finding cost was $7.24 per BOE. The Company's U.S. finding cost for the same five-year period was $7.78 per BOE. Excluding mergers and acquisitions, Anadarko's worldwide and U.S. finding costs for the five-year period 1998-2002 were $7.23 per BOE and $7.44 per BOE, respectively. For the five-year period 1997-2001, Anadarko's worldwide finding cost was $6.66 per BOE and its U.S. finding cost was $7.58 per BOE. For the five-year period 1997-2001, the Company's worldwide and U.S. finding costs excluding mergers and acquisitions were $5.88 per BOE and $6.78 per BOE, respectively.

For 2002, Anadarko's worldwide finding cost was $10.52 per BOE. This compares to $8.53 per BOE in 2001 and $7.19 per BOE in 2000. Anadarko's U.S. finding cost for 2002 was $7.77 per BOE. This compares to $9.60 per BOE in 2001 and $8.49 per BOE in 2000. Excluding mergers and acquisitions, Anadarko's worldwide finding cost for 2002 was $13.43 per BOE compared to $8.75 per BOE in 2001 and $5.83 per BOE in 2000. The Company's U.S. finding cost excluding mergers and acquisitions for 2002 was $8.83 per BOE compared to $9.46 per BOE in 2001 and $6.77 per BOE in 2000. Worldwide finding costs in 2002 increased compared to 2001 due primarily to downward revisions of Venezuelan reserves primarily related to higher prices (see *Critical Accounting Policies*) and large investments made in leases in the eastern Gulf of Mexico that have not yet been drilled. Finding costs in 2001 were higher than 2000 due primarily to increases in oilfield services costs and increased exploration and development activity.

Proved Reserves At the end of 2002 and 2001, Anadarko's proved reserves were 2.3 billion BOE compared to 2.1 billion BOE at year-end 2000. Anadarko's proved reserves have grown 135% over the past three years, primarily as a result of corporate acquisitions, successful exploration projects in the Gulf of Mexico and successful development drilling programs in major domestic fields in core areas onshore and offshore and in Algeria.

The Company's proved natural gas reserves at year-end 2002 were 7.2 trillion cubic feet (Tcf) compared to 7.0 Tcf at year-end 2001 and 6.1 Tcf at year-end 2000. Anadarko's proved gas reserves have increased 186% since year-end 1999, as a result of corporate acquisitions, continued development activity onshore in the U.S. and other producing property acquisitions. Anadarko's crude oil, condensate and NGLs reserves at year-end 2002 were 1.1 billion barrels compared to 1.1 billion barrels at year-end 2001 and 1.0 billion barrels at year-end 2000. Crude oil reserves have risen by 97% over the last three years primarily due to corporate acquisitions, successful exploration projects in the Gulf of Mexico and successful development drilling programs in major domestic fields in core areas onshore and offshore and in Algeria. Crude oil, condensate and NGLs reserves comprise 49% of the Company's proved reserves at year-end 2002 and 2001 and 51% at year-end 2000.

At December 31, 2002, the present value (discounted at 10%) of future net revenues from Anadarko's proved reserves was $21.1 billion, before income taxes, and $14.1 billion, after income taxes, (stated in accordance with the regulations of the Securities and Exchange Commission (SEC) and the Financial Accounting Standards Board (FASB). This present value was calculated based on prices at year-end held flat for the life of the reserves, adjusted for any contractual provisions. The after income taxes increase of $6.1 billion or 76% in 2002 compared to 2001 is primarily due to significantly higher natural gas and higher crude oil prices at year-end 2002, additions of proved reserves related to successful drilling worldwide and corporate acquisitions in 2002. See *Critical Accounting Policies* and *New Accounting Principles and Recent Developments* under Item 7 and *Supplemental Information on Oil and Gas Exploration and Production Activities — Unaudited* in the Consolidated Financial Statements under Item 8 of this Form 10-K.

The present value of future net revenues does not purport to be an estimate of the fair market value of Anadarko's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas.

Acquisitions and Divestitures

The Company's strategy includes an asset acquisition and divestiture program. In 2002, Anadarko acquired approximately 87 MMBOE of proved reserves, including 74 MMBOE located in the United States primarily from the Howell Corporation (Howell) acquisition (64 MMBOE) and including 13 MMBOE located in Qatar. In 2001, the Company acquired approximately 157 MMBOE of proved reserves, located in: Canada, primarily from the Berkley acquisition (99 MMBOE); Qatar and Oman with the Gulfstream Resources Canada Limited (Gulfstream) acquisition (57 MMBOE); and the United States (1 MMBOE). In 2000, Anadarko acquired with the Anadarko Holding merger transaction approximately 912 MMBOE of proved reserves, located primarily in the United States, Canada and Latin America. Excluding corporate acquisitions, during 2000-2002, Anadarko acquired through purchases and trades 38 MMBOE of proved reserves for $112 million. During the same time period, the Company sold properties, either as a strategic exit from a certain area or asset rationalization in existing core areas, of 100 MMBOE with proceeds totaling $397 million. In 2003, the Company will continue to consider dispositions of certain producing properties in non-core areas.

Properties and Leases

Producing Properties The Company owns 9,232 net producing gas wells and 7,011 net producing oil wells worldwide. The following schedule shows the number of developed and undeveloped lease acres in which Anadarko held interests at December 31, 2002.

Acreage

	Developed		Undeveloped		Total	
thousands	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States						
Onshore — Lower 48	2,900	1,959	2,642	1,904	5,542	3,863
Offshore	441	204	1,486	1,129	1,927	1,333
Alaska	25	6	3,144	1,162	3,169	1,168
Total	3,366	2,169	7,272	4,195	10,638	6,364
Canada	1,811	1,024	9,357	3,343	11,168	4,367
Algeria*	219	54	3,775	1,167	3,994	1,221
Other International	570	155	24,896	10,435	25,466	10,590

* Developed acreage in Algeria relates only to areas with an Exploitation License. A portion of the undeveloped acreage in Algeria will be relinquished in the future upon finalization of Exploitation License boundaries.

Land Grant and Other Fee Minerals The Company also owns fee mineral interests on acreage totaling 10,159,000 (gross) or 9,101,000 (net) acres as of December 31, 2002. Of this amount, 7,933,000 (gross) or 7,741,000 (net) acres are within the Company's Land Grant area in Wyoming, Colorado and Utah, which was granted by the federal government to a predecessor of Anadarko Holding in the mid-1800s. The Company holds royalty interests of varying percentages throughout the Land Grant that are subject to exploration and production agreements with third-parties. The Company's fee mineral acreage is primarily undeveloped.

Capital Resources and Liquidity

Capital Expenditures*

millions	**2002**	2001	2000
Development	**$1,079**	$1,641	$ 921
Exploration	**866**	1,030	429
Acquisitions of producing properties	**14**	14	54
Gathering and other	**78**	244	80
Capitalized interest and internal costs related to exploration and development costs	**351**	387	224
Total	**$2,388**	$3,316	$1,708

* Excludes corporate acquisitions

The Company's primary focus for 2002 was to find additional oil and gas reserves and maintain Company-wide production. Anadarko's total capital spending in 2002 was $2.4 billion, a 28% decrease compared to 2001. The decrease from 2001 represents a $562 million decrease in development spending, a $164 million decrease in exploration and a $202 million decrease in gathering and other spending. The decrease in spending for development activities reflects the Company's decision to focus on increasing its inventory of drilling prospects by identifying new reserves through exploration, rather than growing production through development during the down cycle for energy prices earlier in the year.

Anadarko's total capital spending in 2001 was $3.3 billion, a 94% increase compared to 2000. The increase from 2000 represents a $720 million increase in development spending, a $601 million increase in exploration spending and a $287 million increase in spending primarily for general properties and capitalized interest. The development spending increase was primarily in the Lower 48 states, while the exploration spending increase was primarily in the Gulf of Mexico and the Lower 48 states.

The Company funded its capital investment programs in 2002, 2001 and 2000 primarily through cash flow, plus increases in long-term debt, proceeds from property sales and issuances of common stock.

Capital spending for 2003 has been initially set at $2.3 billion, which is a slight decrease compared to 2002. The primary focus of the 2003 budget is to find additional oil and gas reserves and develop existing fields. Anadarko has allocated nearly $1.5 billion to worldwide development projects, primarily for fields in the Gulf of Mexico, western Canada, east and central Texas, north Louisiana, the western states and Algeria. Approximately $380 million is budgeted for exploration programs, mainly in western Canada, the Gulf of Mexico, east Texas, north Louisiana and Alaska. About 70% of the exploration budget will be for drilling compared to 53% in 2002. The remainder of the exploration budget will be used for seismic and lease acquisitions. See *Outlook on Liquidity* for a discussion of the sources of funds for capital spending.

Debt At year-end 2002, Anadarko's total debt was $5.5 billion. This compares to total debt of $5.1 billion at year-end 2001 and $4.0 billion at year-end 2000. The increases in debt are related primarily to the Howell acquisition in 2002 and the Berkley and Gulfstream acquisitions in 2001.

In March 2001, Anadarko issued $650 million of Zero Yield Puttable Contingent Debt Securities (ZYP-CODES) due 2021. In March 2002, ZYP-CODES in the amount of $620 million were put to the Company for repayment and were paid in cash. Holders of the remaining ZYP-CODES have the right to require Anadarko to purchase all or a portion of their ZYP-CODES in March 2004, 2006, 2011 or 2016, at $1,000 per ZYP-CODES.

In February 2002, the Company issued $650 million principal amount of 5⅜% Notes due 2007. In March 2002, the Company issued $400 million principal amount of 6⅛% Notes due 2012. The net proceeds from these issuances were used to reduce floating rate debt and to fund a portion of the ZYP-CODES put to the Company for repayment in March 2002.

In April 2002, Anadarko filed a shelf registration statement with the SEC that permits the issuance of up to $1 billion in debt securities, preferred stock, preferred securities, depositary shares, common stock, warrants, purchase contracts and purchase units. Net proceeds, terms and pricing of the offerings of securities issued under the shelf registration statement will be determined at the time of the offerings.

In September 2002, Anadarko issued $300 million principal amount of 5% Notes due 2012. The net proceeds from the issuance were used to reduce floating rate debt. These notes were issued under the shelf registration statement filed in April 2002.

In October 2002, the Company entered into a 364-Day Revolving Credit Agreement. The agreement provides for $225 million principal amount and expires in 2003. Also in October 2002, Anadarko Canada Corporation, a wholly owned subsidiary of Anadarko, entered into a 364-Day Canadian Credit Agreement. The agreement provides for $300 million principal amount and expires in 2003. The Canadian agreement is fully and unconditionally guaranteed by Anadarko. In addition, the Company has a Revolving Credit Agreement that provides for $225 million principal amount and expires in 2004. As of December 31, 2002, the Company had no outstanding borrowings under these credit agreements.

Preferred Stock During 2002 and 2001, Anadarko repurchased $2 million and $97 million of preferred stock, respectively.

Common Stock Purchase Program In 2001, the Board of Directors authorized the Company to purchase up to $1 billion in shares of Anadarko common stock. The share purchases may be made from time to time, depending on market conditions. Shares may be purchased either in the open market or through privately negotiated transactions. The repurchase program does not obligate Anadarko to acquire any specific number of shares and may be discontinued at any time.

During 2002 and 2001 in conjunction with the stock purchase program, Anadarko sold put options to independent third parties. These put options entitled the holder to sell shares of Anadarko common stock to the Company on certain dates at specified prices. During 2001, Anadarko sold put options for the purchase of a total of 5 million shares of Anadarko common stock with a notional amount of $240 million. A put option for 1 million shares was exercised and put options for 2 million shares expired unexercised in 2001. Put options for the remaining 2 million shares expired unexercised in 2002. In 2002, the Company entered into a put option for 1 million shares of Anadarko common stock with a notional amount of $46 million. The Company received premiums of $7 million during 2002. This put option expired unexercised in 2002. The put options permitted a net-share settlement at the Company's option and did not result in a liability on the consolidated balance sheet.

The following table summarizes purchases under the stock purchase program and the effect of the related put option premiums on the repurchase price.

millions, except per share amounts	2002	2001	Total Program
Shares repurchased	1.0	2.2	3.2
Total paid for shares repurchased	$ 50	$ 116	$ 166
Put premiums settled	(14)	(7)	(21)
Total repurchase price	$ 36	$ 109	$ 145
Average repurchase price per share	$36.08	$49.41	$45.24

Obligations and Commitments

Following is a summary of the Company's future payments on obligations as of December 31, 2002.

	Obligations by Period				
millions	1 Year	2-3 Years	4-5 Years	Later Years	Total
Total debt*	$300	$200	$912	$4,207	$5,619
Operating leases	72	122	105	208	507
Transportation and storage	5	39	28	124	196
Oil and gas activities	—	100	5	—	105

* Holders of the Zero Coupon Convertible Debentures due 2020 had the right to put the debentures to the Company in March 2003 at the accrued value of $383 million. This debt instrument has been reflected in later years in the table above. Holders of the ZYP-CODES due 2021 may put the remaining $30 million principal amount of the ZYP-CODES to the Company in 2004.

Synthetic Leases Anadarko has two lease arrangements for its corporate office buildings in The Woodlands, Texas. The development and acquisition of the properties were financed by special purpose entities (SPEs) sponsored by a financial institution. The total amount funded under these leases was $213 million. In addition, the Company has a total lease payment obligation of $11 million related to aircraft operating leases financed by synthetic leases. The table above includes lease payment obligations related to these synthetic leases under operating leases. For additional information see *Note 17 — Commitments* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Oil and Gas Activities As is common in the oil and gas industry, Anadarko has various contractual commitments pertaining to exploration, development and production activities. The amounts in the previous table reflect obligations and commitments that are not included in the 2003 capital budget. Following is a description of the Company's significant operating obligations and commitments related to oil and gas activities.

Production Platform In April 2002, the Company signed an agreement under which a floating production platform for its Marco Polo discovery in Green Canyon Block 608 of the Gulf of Mexico will be installed. Since the Company's obligation related to the agreement begins at the time of project completion, the table above does not include any amounts related to this agreement. For additional information see *Note 17 — Commitments* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Drilling and Work Commitments Anadarko has various work related commitments for, among other things, drilling wells, obtaining and processing seismic and fulfilling rig commitments. The above table includes drilling and work related commitments of $105 million, comprised of $37 million in the United States, $35 million in Canada, $24 million in Algeria and $9 million in other international locations. The commitments in Algeria are related primarily to exploration and development contracts with Sonatrach, who is the registered owner of 4.9% of the Company's outstanding common stock.

Sales Commitments In Canada, the Company has commitments to deliver gas under fixed price contracts. The gas volumes to be delivered under these contracts are as follows:

	Commitments by Period			
	1 Year	2-3 Years	4-5 Years	Total
Natural Gas				
Volume — million MMBtu	25	33	5	63
Price per MMBtu	$2.01	$1.92	$1.69	$1.93

MMBtu — million British thermal units

Other The Company has defined benefit pension plans and supplemental plans that are non-contributory pension plans. In January 2003, the Company made a $52 million contribution to a defined benefit pension plan.

For additional information on contracts and arrangements the Company enters into from time to time see *Note 7 — Debt, Note 8 — Financial Instruments, Note 18 — Pension Plans, Other Postretirement Benefits and Employee Savings Plans* and *Note 19 — Contingencies* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Outlook on Liquidity

Anadarko's net cash from operating activities in 2002 was $2.2 billion compared to $3.3 billion in 2001 and $1.5 billion in 2000. The decrease in 2002 cash flow is attributed to a significant decrease in natural gas prices. The Company's original capital expenditure budget for 2003 has been set at $2.3 billion and net cash from operating activities in 2003 is expected to be about $2.6 billion. The Company plans to use a portion of 2003 cash flow to repay about $300 million in debt. Cash flow from operations will vary depending upon, among other things, actual commodity prices received throughout the year. The Company intends to adjust capital expenditures to reflect changes in its cash flow from operations. The Company's cash flow and capital expenditure estimates for 2003 were based on prices far below where oil and gas prices were trading in the first quarter of 2003. If higher prices are realized, the Company may expand the drilling program, make targeted acquisitions or further reduce debt. The Company has a stock buyback program to purchase up to $1 billion in shares of Anadarko common stock. Any stock repurchases for 2003 are not included in the announced capital expenditure budget and are not currently anticipated.

Both exchange and over-the-counter traded financial derivative instruments are subject to margin deposit requirements. Margin deposits are required by the Company whenever its unrealized losses with a counterparty exceed pre-determined credit limits. Given the Company's sizable hedge position and price volatility, the Company may be required from time to time to advance cash to its counterparties in order to satisfy these margin deposit requirements. During January and February 2003, the Company's margin deposit requirements have ranged from zero to $125 million. Based on NYMEX future strip prices, the Company's margin deposit requirement was $25 million on March 7, 2003.

Anadarko believes that operating cash flow and existing or available credit facilities will be adequate to meet its capital and operating requirements for 2003. The Company funds its day-to-day operating expenses and capital expenditures from operating cash flows, supplemented as needed by short-term borrowings under commercial paper, money market loans or credit facility borrowings. To facilitate such borrowings, the Company has in place $750 million in committed credit facilities, which are supplemented by various non-committed credit lines that may be offered by certain banks from time to time at then-quoted rates. It is the Company's policy to limit commercial paper borrowing to levels that are fully back-stopped by unused balances from its committed credit facilities. The Company may choose to refinance certain portions of these short-term borrowings by issuing long-term debt in the public or private debt markets. To facilitate such financings, the Company may file shelf registrations in advance with the SEC. The Company continuously monitors its debt position and coordinates its capital expenditure program with expected cash flows and projected debt repayment schedules. The Company will continue to evaluate funding alternatives, including property sales and additional borrowing, to secure other funds for additional capital expenditures and stock repurchases. At this time, Anadarko has no plans to issue common stock other than through its Dividend Reinvestment and Stock Purchase Plan, through the exercise of stock options, possible redemption of convertible debt securities or through the Company's Employee Savings Plan and Employee Stock Ownership Plan equity funded contributions. See *Regulatory Matters and Additional Factors Affecting Business* for additional information.

Dividends

In 2002, Anadarko paid $80 million in dividends to its common stockholders (7.5 cents per share in the first, second and third quarters and 10 cents per share in the fourth quarter). In 2001, Anadarko paid $57 million in dividends to its common stockholders (5 cents per share in the first, second and third quarters and 7.5 cents per share in the fourth quarter). The dividend amount in 2000 was $39 million (5 cents per share per quarter). Anadarko has paid a dividend to its common stockholders continuously since becoming an independent company in 1986.

The Company's credit agreements allow for a maximum capitalization ratio of 60% debt, exclusive of the effect of any non-cash write-downs. As of December 31, 2002, Anadarko's capitalization ratio was 44% debt. While there is no specific restriction on paying dividends, under the maximum debt capitalization ratio retained earnings were not restricted as to the payment of dividends at December 31, 2002. The amount of future common stock dividends will depend on earnings, financial conditions, capital requirements and other factors, and will be determined by the Board of Directors on a quarterly basis.

In 2002, 2001 and 2000, the Company also paid $6 million, $7 million and $11 million, respectively, in preferred stock dividends. In 2003, the preferred stock dividends are expected to be $5 million.

Critical Accounting Policies

Financial Statements and Use of Estimates The consolidated financial statements include the accounts of Anadarko and its subsidiaries. All significant intercompany transactions have been eliminated. The Company accounts for investments in affiliated companies (generally 20% to 50% owned) using the equity method of accounting. The financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. In preparing financial statements, Management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, Management reviews its estimates, including those related to litigation, environmental liabilities, income taxes and determination of proved reserves. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Properties and Equipment The Company uses the full cost method of accounting for exploration and development activities as defined by the SEC. Under this method of accounting, the costs for unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country. The application of the full cost method of accounting for oil and gas properties generally results in higher capitalized costs and higher DD&A rates compared to the successful efforts method of accounting for oil and gas properties.

The sum of net capitalized costs and estimated future development and abandonment costs of oil and gas properties and mineral investments is amortized using the unit-of-production method. All other properties are stated at original cost and depreciated on the straight-line basis over the useful life of the assets, which ranges from three to 40 years.

Proved Reserves Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10(a) (2i), (2ii), (2iii), (3) and (4), are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Prices do not include the effect of derivative instruments entered into by the Company.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for re-completion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

The Company emphasizes that the volumes of reserves are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data as well as production performance data. These estimates, made by the Company's engineers, are reviewed and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in assumptions based on, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to uneconomic conditions.

Under the terms of Anadarko's risk service contract with the national oil company of Venezuela, Anadarko earns a fee that is translated into barrels of oil based on current prices (economic interest method). This means that higher oil prices reduce the Company's reported production volumes and reserves from that project and lower oil prices increase reported production volumes and reserves. Production volume and reserve changes due to the prices used to determine the Company's economic interest have no impact on the value of the project. The following table shows the impact on 2002 at various price levels to demonstrate the effect of the economic interest method.

	Economic Interest Method		
NYMEX price per barrel	**$36.00**	**$30.00**	**$24.00**
Revenues — millions	$ 88	$ 88	$ 88
Production volumes — MMBOE	3	4	5
Reserves — MMBOE	65	78	98

Costs Excluded Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent costs of investments in unproved properties and major development projects. Anadarko excludes these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the costs to be amortized (the DD&A pool) or a charge is made against earnings for those international operations where a reserve base has not yet been established. For international operations where a reserve base has not yet been established, an impairment requiring a charge to earnings may be indicated through evaluation of drilling results, relinquishing drilling rights or other information. Costs excluded for oil and gas properties are generally classified and evaluated as significant or individually insignificant properties.

Significant properties, comprised primarily of costs associated with domestic offshore blocks, Alaska, the Land Grant and other international areas, are individually evaluated each quarter by the Company's exploration and engineering staff. Non-producing leases are evaluated based on the progress of the Company's exploration program to date. Exploration costs are transferred to the DD&A pool upon completion of drilling individual wells. The Company has a 10 to 15 year exploration and evaluation program for the Land Grant acreage. Costs will be transferred accordingly to the DD&A pool over the length of the program. The Land Grant's mineral interests (both working and royalty interests) are owned by the Company in perpetuity. All other significant properties are evaluated over a five- to ten- year period, depending on the lease term.

Insignificant properties are comprised primarily of costs associated with onshore properties in the United States and Canada. Non-producing leases are transferred to the DD&A pool over a three- to five- year period based on the average lease period. Exploration costs are transferred to the DD&A pool upon completion of evaluation.

Capitalized Interest SFAS No. 34, ''Capitalization of Interest Cost,'' provides standards for the capitalization of interest cost as part of the historical cost of acquiring assets. Under FASB-Interpretation (FIN) No. 33 ''Applying FASB Statement No. 34 to Oil and Gas Producing Operations Accounted for by the Full Cost Method,'' costs of investments in unproved properties and major development projects, on which DD&A expense is not currently taken and on which exploration or development activities are in progress, qualify for capitalization of interest. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on debt by the amount of qualifying costs excluded. Capitalized interest cannot exceed gross interest expense. As costs excluded are transferred to the DD&A pool, the associated capitalized interest is also transferred to the DD&A pool.

Ceiling Test Companies that use the full cost method of accounting for oil and gas exploration and development activities are required to perform a ceiling test each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed on a country-by-country basis. The test determines a limit, or ceiling, on the book value of oil and gas properties. That limit is basically the after tax present value of the future net cash flows from proved crude oil and natural gas reserves. This ceiling is compared to the net book value of the oil and gas properties reduced by any related deferred income tax liability. If the net book value reduced by the related deferred income taxes exceeds the ceiling, an impairment or non-cash write down is required. A ceiling test impairment can give Anadarko a significant loss for a particular period; however, future DD&A expense would be reduced. Shown below is a summary of the ceiling test calculation and description of the major components.

Ceiling Test Calculation

Present Value of Oil and Gas Properties (PV 10)
+ Costs Excluded
– Income Taxes
= Ceiling

Net Oil and Gas Properties and Equipment
– Deferred Income Tax Liability
= Net Investment

Ceiling – Net Investment = Cushion (Write-off) After Income Taxes

Present Value of Oil and Gas Properties (PV 10) Estimates of future net cash flows from proved reserves of gas, oil, condensate and NGLs are made in accordance with SEC Regulation S-X Rule 4-10. The present value of oil and gas properties represents the estimated future net cash flows from proved oil and gas reserves, discounted using a prescribed 10% discount rate. Proved oil and gas reserve estimates, which are determined by the Company's engineers, are reviewed and revised as reservoir performance, prices and other economic conditions change. Future net revenues are calculated based on estimated production volumes generally using the oil and gas prices in effect on the last day of the quarter, held flat for the life of the reserves. Future net revenues are reduced by estimated future production and development costs based on quarter-end cost levels, assuming continuation of existing economic conditions.

Due to the volatility of commodity prices, the oil and gas prices on the last day of the quarter significantly impact the calculation of the PV 10. At year-end 2002, Anadarko's ceiling tests were based on NYMEX prices of $4.60 per Mcf for natural gas and $31.20 per barrel for crude oil. The NYMEX prices are adjusted by location and quality differentials, as appropriate, to determine Anadarko's realized prices. The present value of future net cash flows does not purport to be an estimate of the fair market value of Anadarko's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas.

Costs Excluded Costs excluded are capitalized costs of investments in unproved properties and major development projects. These costs are excluded from capitalized costs being amortized through DD&A expense. Anadarko excludes all costs until proved reserves are found or until it is determined that the costs are impaired. When proved reserves are found, the decrease in costs excluded is offset by an increase in PV 10; thereby, generally increasing the ceiling. When proved reserves are not found, the decrease in costs excluded is not offset by an increase in PV 10; thereby, decreasing the ceiling.

Income Taxes Future income taxes are based on the existing tax rates applied to the difference between the total of the present value of the future net cash flows plus costs excluded less the tax basis of the oil and gas properties. The effect of tax loss carryforwards and credits related to oil and gas activities is considered in determining income taxes.

Net Oil and Gas Properties and Equipment Net oil and gas properties and equipment are the capitalized costs related to oil and gas activities less the accumulated DD&A. Under the full cost method of accounting, the costs for unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. The net capitalized costs are depreciated using the unit-of-production method. Net properties and equipment increase due to capital expenditures or acquisitions and decrease due to DD&A expense, property divestitures or ceiling test impairments.

Deferred Income Tax Liability Deferred income taxes related only to oil and gas properties are included in the deferred income tax liability.

Derivative Instruments Anadarko uses derivative instruments for various risk management purposes. Effective January 2001, derivative instruments utilized to manage or reduce commodity price risk related to the Company's equity production were accounted for under the provisions of SFAS No. 133 ''Accounting for Derivative Instruments and Hedging Activities.'' Under this statement, all derivatives are carried on the balance sheet at fair value. Realized gains and losses are recognized in sales when the underlying physical gas and oil production is sold. Accordingly, realized derivative gains and losses are generally offset by similar changes in the realized value of the underlying physical gas and oil production. Realized derivative gains and losses are reflected in the average sales price of the physical gas and oil production.

Accounting for unrealized gains and losses is dependent on whether the derivative instruments have been designated and qualify as part of a hedging relationship. Derivative instruments may be designated as a hedge of exposure to changes in fair values, cash flows or foreign currencies, if certain conditions are met. Unrealized gains and losses on derivative instruments that do not meet the conditions to qualify for hedge accounting are recognized currently in other (income) expense.

If the hedged exposure is to changes in fair value, the gains and losses on the derivative instrument, as well as the offsetting losses and gains on the hedged item, are recognized currently in earnings. Consequently, if gains and losses on the derivative instrument and the related hedge item do not completely offset, the difference (i.e., ineffective portion of the hedge) is recognized currently in earnings.

If the hedged exposure is a cash flow exposure, the effective portion of the gains and losses on the derivative instrument is reported as a component of accumulated other comprehensive income and reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The ineffective portion of the gains and losses from the derivative instrument, if any, as well as any amounts excluded from the assessment of the cash flow hedges' effectiveness are recognized currently in other (income) expense.

Derivative instruments, as well as physical delivery purchase and sale contracts, utilized in the Company's energy trading activities and in the management of price risk associated with the Company's firm transportation keep-whole commitment (see *Derivative Instruments* under Item 7a of this Form 10-K) were accounted for under the mark-to-market accounting method pursuant to EITF Issue No. 98-10, ''Accounting for Contracts Involved in Energy Trading and Risk Management Activities.'' Under this method, the derivatives and physical delivery contracts are revalued in each accounting period and unrealized gains and losses are recorded in the statement of income and carried as assets or liabilities on the balance sheet. EITF Issue No. 98-10 was rescinded in October 2002. As a result, mark-to-market accounting is precluded for energy trading contracts that are not derivatives pursuant to SFAS No. 133. The recission of EITF Issue No. 98-10 is effective for contracts entered into after October 25, 2002 and is effective for all contracts January 1, 2003. Substantially all of the Company's physical delivery energy trading contracts are considered to be derivatives pursuant to SFAS No. 133. Therefore, the recission of EITF Issue No. 98-10 did not have a significant impact on the accounting for energy trading contracts as those contracts continue to be marked-to-market in accordance with SFAS No. 133.

The Company's derivative instruments associated with the marketing and trading activities are generally either exchange traded or valued by reference to a commodity that is traded in a liquid market. Valuation is determined by reference to readily available public data. Option valuations are based on the Black-Scholes option pricing model and verified against third-party quotations. The fair value of the short-term portion of the firm transportation keep-whole agreement is calculated with quoted natural gas basis prices. Basis is the difference in value between gas at various delivery points and the NYMEX gas futures contract price. Management believes that natural gas basis price quotes beyond the next twelve months are not reliable indicators of fair value due to decreasing liquidity. Accordingly, the fair value of the long-term portion is estimated based on historical natural gas basis prices, discounted at 10% per year. Management also periodically evaluates the supply and demand factors (such as expected drilling activity, anticipated pipeline construction projects, expected changes in demand at pipeline delivery points, etc.) that may impact the future market value of the firm transportation capacity to determine if the estimated fair value should be adjusted.

New Accounting Principles and Recent Developments

New Accounting Principles For information on New Accounting Principles see *Note 1 — Summary of Significant Accounting Policies* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Proved Reserves The SEC is currently in the process of obtaining information from oil and gas exploration companies operating offshore (including Anadarko) to assess the criteria being used by industry to determine proved reserves related to new field discoveries offshore. The SEC regulations allow companies to recognize proved reserves if economic producibility is supported by either an actual production test (flow test) or conclusive formation testing. In the absence of a production test, compelling technical data must exist to recognize proved reserves related to the initial discovery of a field. In deep-water environments where production tests are extremely expensive, the industry has increasingly depended on advanced technical testing to support economic producibility.

Anadarko has recorded proved reserves related to the initial discovery of four offshore fields based on conclusive formation tests rather than actual production tests. As of December 31, 2002, these proved reserves amounted to 100 MMBOE or less than 5% of Anadarko's total worldwide proved reserves. The Company is currently developing all of these fields and expects the majority of the production from these fields to commence during 2004. Anadarko believes the reserves were properly classified.

Most of these reserves are located at Marco Polo, a deep-water field under development at Green Canyon Block 608. Ryder Scott Company, an independent petroleum consulting company, has reviewed Anadarko's technical data and studies used to support the classification of proved reserves at the Marco Polo field. Ryder Scott's review concludes that the reserves meet the SEC's definition of proved reserves. A copy of the Ryder Scott report is attached as Exhibit 99.3 to this Form 10-K.

Anadarko has furnished the information requested to the SEC and is unable to predict the likely outcome of the SEC's staff review of this industry practice. The issue is not expected to have a material impact on the Company's proved reserves or financial results; however, if the issue is not favorably resolved, Anadarko may be required to revise its proved reserve estimates, which would affect Anadarko's finding costs per barrel, reserve replacement ratios and DD&A expense, until flow tests are conducted or production commences.

Regulatory Matters and Additional Factors Affecting Business

Forward Looking Statements *The Company has made in this report, and may from time to time otherwise make in other public filings, press releases and discussions with Company management, forward looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 concerning the Company's operations, economic performance and financial condition. These forward looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, and those statements preceded by, followed by or that otherwise include the words "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should" or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward looking statements contained in the Private Securities Litigation Reform Act of 1995. Such statements are subject to various risks and uncertainties, and actual results could differ materially from those expressed or implied by such statements due to a number of* *factors in addition to those discussed below and elsewhere in this Form 10-K and in the Company's other public filings, press releases and discussions with Company management. Anadarko undertakes no obligation to publicly update or revise any forward looking statements.*

Commodity Pricing and Demand Crude oil prices continue to be affected by political developments worldwide, pricing decisions and production quotas of OPEC and the volatile trading patterns in the commodity futures markets. Natural gas prices also continue to be highly volatile. In periods of sharply lower commodity prices, the Company may curtail production and capital spending projects, as well as delay or defer drilling wells in certain areas because of lower cash flows. Changes in crude oil and natural gas prices can impact the Company's determination of proved reserves and the Company's calculation of the standardized measure of discounted future net cash flows relating to oil and gas reserves. In addition, demand for oil and gas in the U.S. and worldwide may affect the Company's level of production.

Under the full cost method of accounting, a non-cash charge to earnings related to the carrying value of the Company's oil and gas properties on a country-by-country basis may be required when prices are low. Whether the Company will be required to take such a charge depends on the prices for crude oil and natural gas at the end of any quarter, as well as the effect of both capital expenditures and changes to proved reserves during that quarter. While this non-cash charge can give Anadarko a significant reported loss for the period, future expenses for DD&A will be reduced.

Environmental and Safety The Company's oil and gas operations and properties are subject to numerous federal, state and local laws and regulations relating to environmental protection from the time oil and gas projects commence until abandonment. These laws and regulations govern, among other things, the amounts and types of substances and materials that may be released into the environment, the issuance of permits in connection with exploration, drilling and production activities, the release of emissions into the atmosphere, the discharge and disposition of generated waste materials, offshore oil and gas operations, the reclamation and abandonment of wells and facility sites and the remediation of contaminated sites. In addition, these laws and regulations may impose substantial liabilities for the Company's failure to comply with them or for any contamination resulting from the Company's operations.

Anadarko takes the issue of environmental stewardship very seriously and works diligently to comply with applicable environmental and safety rules and regulations. Compliance with such laws and regulations has not had a material effect on the Company's operations or financial condition in the past. However, because environmental laws and regulations are becoming increasingly more stringent, there can be no assurances that such laws and regulations or any environmental law or regulation enacted in the future will not have a material effect on the Company's operations or financial condition.

For a description of certain environmental proceedings in which the Company is involved, see *Note 19 — Contingencies* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Exploration and Operating Risks The Company's business is subject to all of the operating risks normally associated with the exploration for and production of oil and gas, including blowouts, cratering and fire, any of which could result in damage to, or destruction of, oil and gas wells or formations or production facilities and other property and injury to persons.

As protection against financial loss resulting from these operating hazards, the Company maintains insurance coverage, including certain physical damage, employer's liability, comprehensive general liability and worker's compensation insurance. Although Anadarko is not insured against all risks in all aspects of its business, such as political risk, business interruption risk and risk of major terrorist attacks, the Company believes that the coverage it maintains is customary for companies engaged in similar operations. The occurrence of a significant event against which the Company is not fully insured could have a material adverse effect on the Company's financial position.

Development Risks The Company is involved in several large development projects. Key factors that may affect the timing and outcome of such projects include: project approvals by joint venture partners; timely issuance of permits and licenses by governmental agencies; manufacturing and delivery schedules of critical equipment; and commercial arrangements for pipelines and related equipment to transport and market hydrocarbons. In large development projects, these uncertainties are usually resolved, but delays and differences between estimated and actual timing of critical events are commonplace and may, therefore, affect the forward-looking statements related to large development projects.

Domestic Governmental Risks The domestic operations of the Company have been, and at times in the future may be, affected by political developments and by federal, state and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations.

Foreign Operations Risk The Company's operations in areas outside the U.S. are subject to various risks inherent in foreign operations. These risks may include, among other things, loss of revenue, property and equipment as a result of hazards such as expropriation, war, insurrection and other political risks, increases in taxes and governmental royalties, renegotiation of contracts with governmental entities, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations and other uncertainties arising out of foreign government sovereignty over the Company's international operations. The Company's international operations may also be adversely affected by laws and policies of the United States affecting foreign trade and taxation. To date, the Company's international operations have not been materially affected by these risks.

Competition The oil and gas business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of oil and gas production. The Company's competitors include the major oil companies, independent oil and gas concerns, individual producers, gas marketers and major pipeline companies, as well as participants in other industries supplying energy and fuel to industrial, commercial and individual consumers.

Other Regulatory agencies in certain states and countries have authority to issue permits for seismic exploration and the drilling of wells, regulate well spacing, prevent the waste of oil and gas resources through proration and regulate environmental matters.

Operations conducted by the Company on federal oil and gas leases must comply with numerous regulatory restrictions, including various nondiscrimination statutes. Additionally, certain operations must be conducted pursuant to appropriate permits issued by the Bureau of Land Management and the Minerals Management Service of the U.S. Department of the Interior. In addition to the standard permit process, federal leases and most international concessions require a complete environmental impact assessment prior to authorizing an exploration or development plan.

Legal Proceedings

General The Company is a defendant in a number of lawsuits and is involved in governmental proceedings arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. The Company has also been named as a defendant in various personal injury claims, including numerous claims by employees of third-party contractors alleging exposure to asbestos and benzene while working at a refinery in Corpus Christi, Texas, which Anadarko Holding sold in segments in 1987 and 1989. While the ultimate outcome and impact on the Company cannot be predicted with certainty, Management believes that the resolution of these proceedings will not have a material adverse effect on the consolidated financial position of the Company, although results of operations and cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

For a description of certain legal proceedings in which the Company is involved, see *Legal Proceedings* under Item 3 of this Form 10-K.

Item 7a. Quantitative and Qualitative Disclosures About Market Risk

Derivative Instruments Anadarko's commodity derivative instruments currently are comprised of futures, swaps and options contracts. The volume of commodity derivative instruments utilized by the Company to hedge its market price risk and in its energy trading operation can vary during the year within the boundaries of its established risk management policy guidelines. For information regarding the Company's accounting policies related to derivatives and additional information related to the Company's derivative instruments, see *Note 1 — Summary of Significant Accounting Policies* and *Note 8 — Financial Instruments* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Derivative Instruments Held for Non-Trading Purposes The Company had equity production hedges of 334 billion cubic feet of natural gas and 28 million barrels of crude oil as of December 31, 2002. As of December 31, 2002, the Company had a net unrealized loss of $154 million before taxes on these commodity derivative instruments. Based upon an analysis utilizing the actual derivative contractual volumes, a 10% increase in commodity prices would result in an additional loss on these commodity derivative instruments of approximately $166 million. However, this loss would be substantially offset by a gain in the value of that portion of the Company's equity production that is hedged.

Derivative Instruments Held for Trading Purposes As of December 31, 2002, the Company had a net unrealized gain of $24 million (gains of $73 million and losses of $49 million) on commodity derivative instruments entered into for trading purposes and a net unrealized loss of $30 million (gains of $16 million and losses of $46 million) on physical contracts entered into for trading purposes. Based upon an analysis utilizing the actual derivative contractual volumes and assuming a 10% decrease in underlying commodity prices, the potential additional loss on the derivative instruments would be approximately $20 million.

Firm Transportation Keep-Whole Agreement Anadarko Holding Company (Anadarko Holding) was a party to several long-term firm gas transportation agreements that supported its gas marketing program within its gathering, processing and marketing (GPM) business segment, which was sold in 1999 to Duke Energy (Duke). As part of the GPM disposition, Anadarko Holding agreed to pay Duke if transportation market values fall below the fixed contract transportation rates, while Duke will pay Anadarko Holding if the transportation market values exceed the contract transportation rates (keep-whole agreement). This keep-whole agreement will be in effect until the earlier of each contract's expiration date or February 2009. The Company may periodically use derivative instruments to reduce its exposure under the keep-whole agreement to potential decreases in future transportation market values. Due to decreased liquidity, the use of derivative instruments to manage this risk is generally limited to the forward twelve months. As of December 31, 2002, accounts payable included $5 million and other long-term liabilities included $68 million related to this agreement. As of December 31, 2001, accounts payable included $27 million and other long-term liabilities included $80 million related to this agreement. A 10% unfavorable change in prices on the short-term portion of the keep-whole agreement would result in an additional loss of $10 million. The future gain or loss from this agreement cannot be accurately predicted. For additional information related to the keep-whole agreement, see *Note 8 — Financial Instruments* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

For additional information regarding the Company's marketing and trading portfolio and the firm transportation keep-whole agreement see *Marketing Strategies* under Item 7 of this Form 10-K.

Commodity Price Risk As a result of low natural gas and oil prices at September 30, 2001, Anadarko's capitalized costs of oil and gas properties primarily in the United States, Canada and Argentina exceeded the ceiling limitation and the Company recorded a $2.5 billion ($1.6 billion after taxes) non-cash write-down in the third quarter of 2001. The pre-tax write-down is reflected as additional accumulated depreciation, depletion and amortization. See *Critical Accounting Policies* and *Regulatory Matters and Additional Factors Affecting Business* under Item 7 of this Form 10-K.

Interest Rate Risk Anadarko is also exposed to risk resulting from changes in interest rates as a result of the Company's variable and fixed interest rate debt. The Company believes the potential effect that reasonably possible near term changes in interest rates may have on the fair value of the Company's various debt instruments is not material.

Foreign Currency Risk The Company's Canadian subsidiaries use the Canadian dollar as their functional currency. The Company's other international subsidiaries use the U.S. dollar as their functional currency. To the extent that business transactions in these countries are not denominated in the respective country's functional currency, the Company is exposed to foreign currency exchange rate risk.

At December 31, 2002 and 2001, a Canadian subsidiary had $98 million and $187 million, respectively, outstanding of fixed-rate notes and debentures denominated in U.S. dollars. The potential foreign currency remeasurement impact on earnings from a 10% increase in the December 31, 2002 Canadian exchange rate would be about $9 million based on the outstanding debt at December 31, 2002.

At December 31, 2002 and 2001, the Company's Latin American subsidiaries had foreign deferred tax liabilities denominated in the local currency equivalent totaling $49 million and $78 million, respectively. In conjunction with the sale of certain properties in 2001, the Company indemnified a purchaser for the use of local tax losses denominated in the local currency equivalent totaling $22 million. The potential foreign currency remeasurement impact on net earnings from a 10% increase in the year-end Latin American exchange rates would be approximately $4 million.

For additional information related to foreign currency risk see *Note 8 — Financial Instruments* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Item 8. Financial Statements and Supplementary Data

ANADARKO PETROLEUM CORPORATION
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ANADARKO PETROLEUM CORPORATION
REPORT OF MANAGEMENT

The Management of Anadarko Petroleum Corporation is responsible for the preparation and integrity of all information contained in the accompanying consolidated financial statements. The financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. In preparing the financial statements, Management makes informed judgments and estimates.

Management maintains and relies on the Company's system of internal accounting controls. Although no system can ensure elimination of all errors and irregularities, this system is designed to provide reasonable assurance that assets are safeguarded, transactions are executed in accordance with Management's authorization and accounting records are reliable as a basis for the preparation of financial statements. This system includes the selection and training of qualified personnel, an organizational structure providing appropriate delegation of authority and division of responsibility, the establishment of accounting and business policies for the Company and the conduct of internal audits.

The Board of Directors pursues its responsibility for the consolidated financial information through its Audit Committee, which is composed solely of Directors who are independent. The Audit Committee recommends to the Board of Directors the selection of independent auditors and reviews their fee arrangements. The Audit Committee meets periodically with Management, the internal auditors and the independent auditors to review that each is carrying out its responsibilities. Both the internal and the independent auditors have full and free access to the Audit Committee to discuss auditing and financial reporting matters.

We believe that Anadarko's policies and procedures, including its system of internal accounting controls, provide reasonable assurance that the financial statements are prepared in accordance with the applicable securities rules and regulations.

John N. Seitz
President and Chief Executive Officer

Michael E. Rose
Executive Vice President and
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of income, stockholders' equity, comprehensive income and cash flows for each of the years in the three-year period ended December 31, 2002. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2002, the Company changed its method of accounting for goodwill, effective January 1, 2001, the Company changed its method of accounting for derivative instruments, and effective January 1, 2000, the Company changed its method of accounting for foreign crude oil inventories.

KPMG LLP

Houston, Texas
January 31, 2003

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

millions except per share amounts	Years Ended December 31 **2002**	2001	2000
Revenues			
Gas sales	**$1,835**	$2,952	$1,615
Oil and condensate sales	**1,690**	1,397	946
Natural gas liquids sales	**222**	256	264
Other sales	**113**	113	86
Total	**3,860**	4,718	2,911
Costs and Expenses			
Operating expenses	**747**	769	487
Administrative and general	**314**	292	270
Depreciation, depletion and amortization	**1,121**	1,154	593
Other taxes	**214**	247	128
Impairments related to oil and gas properties	**39**	2,546	50
Amortization of goodwill	**—**	73	31
Total	**2,435**	5,081	1,559
Operating Income (Loss)	**1,425**	(363)	1,352
Other (Income) Expense			
Interest expense	**203**	92	93
Other (income) expense	**15**	(65)	(167)
Total	**218**	27	(74)
Income (Loss) Before Income Taxes	**1,207**	(390)	1,426
Income Tax Expense (Benefit)	**376**	(214)	602
Net Income (Loss) Before Cumulative Effect of Change in Accounting Principle	**$ 831**	$ (176)	$ 824
Preferred Stock Dividends	**6**	7	11
Net Income (Loss) Available to Common Stockholders Before Cumulative Effect of Change in Accounting Principle	**$ 825**	$ (183)	$ 813
Cumulative Effect of Change in Accounting Principle	**—**	5	17
Net Income (Loss) Available to Common Stockholders	**$ 825**	$ (188)	$ 796
Per Common Share			
Net income (loss) — before change in accounting principle — basic	**$ 3.32**	$ (0.73)	$ 4.42
Net income (loss) — before change in accounting principle — diluted	**$ 3.21**	$ (0.73)	$ 4.25
Change in accounting principle — basic	**$ —**	$ (0.02)	$ (0.09)
Change in accounting principle — diluted	**$ —**	$ (0.02)	$ (0.09)
Net income (loss) — basic	**$ 3.32**	$ (0.75)	$ 4.32
Net income (loss) — diluted	**$ 3.21**	$ (0.75)	$ 4.16
Dividends	**$0.325**	$0.225	$ 0.20
Average Number of Common Shares Outstanding — Basic	**248**	250	184
Average Number of Common Shares Outstanding — Diluted	**260**	250	193

See accompanying notes to consolidated financial statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

millions	December 31 2002	2001
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 34**	$ 37
Accounts receivable, net of allowance:		
Customers	**673**	532
Others	**435**	486
Other current assets	**138**	146
Total	**1,280**	1,201
Properties and Equipment		
Original cost (includes unproved properties of $3,085 and $3,573 as of December 31, 2002 and 2001, respectively)	**22,595**	20,088
Less accumulated depreciation, depletion and amortization	**7,497**	6,451
Net properties and equipment — based on the full cost method of accounting for oil and gas properties	**15,098**	13,637
Other Assets	**436**	503
Goodwill	**1,434**	1,430
Total Assets	**$18,248**	$16,771
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	**$ 1,050**	$ 1,132
Accrued expenses	**511**	257
Current portion, notes and debentures	**300**	412
Total	**1,861**	1,801
Long-term Debt	**5,171**	4,638
Other Long-term Liabilities		
Deferred income taxes	**3,633**	3,451
Other	**611**	516
Total	**4,244**	3,967
Stockholders' Equity		
Preferred stock, par value $1.00 per share (2.0 million shares authorized, 0.1 million shares issued as of December 31, 2002 and 2001)	**101**	103
Common stock, par value $0.10 per share (450.0 million shares authorized, 254.6 million and 254.1 million shares issued as of December 31, 2002 and 2001, respectively)	**25**	25
Paid-in capital	**5,347**	5,336
Retained earnings	**2,021**	1,276
Treasury stock (3.2 million and 2.2 million shares as of December 31, 2002 and 2001, respectively)	**(166)**	(116)
Deferred compensation and ESOP (0.7 million and 0.9 million shares as of December 31, 2002 and 2001, respectively)	**(63)**	(96)
Executives and Directors Benefits Trust, at market value (2.0 million shares as of December 31, 2002 and 2001)	**(95)**	(114)
Accumulated other comprehensive loss		
Unrealized loss on derivative instruments	**(85)**	—
Foreign currency translation adjustments	**(37)**	(46)
Minimum pension liability	**(76)**	(3)
Total	**(198)**	(49)
Total	**6,972**	6,365
Commitments and Contingencies	**—**	—
Total Liabilities and Stockholders' Equity	**$18,248**	$16,771

See accompanying notes to consolidated financial statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

millions	**2002**	2001	2000
	Years Ended December 31		
Preferred Stock			
Balance at beginning of year	**$ 103**	$ 200	$ 200
Preferred stock repurchased	**(2)**	(97)	—
Balance at end of year	**101**	103	200
Common Stock			
Balance at beginning of year	**25**	25	13
Common stock issued	**—**	—	12
Balance at end of year	**25**	25	25
Paid-in Capital			
Balance at beginning of year	**5,336**	5,303	634
Common stock and common stock put options issued	**30**	51	4,592
Revaluation to market for Executives and Directors Benefits Trust	**(19)**	(31)	77
Preferred stock repurchased	**—**	13	—
Balance at end of year	**5,347**	5,336	5,303
Retained Earnings			
Balance at beginning of year	**1,276**	1,521	764
Net income (loss)	**831**	(181)	807
Dividends paid — preferred	**(6)**	(7)	(11)
Dividends paid — common	**(80)**	(57)	(39)
Balance at end of year	**2,021**	1,276	1,521
Treasury Stock			
Balance at beginning of year	**(116)**	—	—
Purchase of treasury stock	**(50)**	(116)	—
Balance at end of year	**(166)**	(116)	—
Deferred Compensation and ESOP			
Balance at beginning of year	**(96)**	(121)	(8)
Issuance of restricted stock	**(7)**	(15)	(82)
Acquisition of ESOP	**—**	—	(74)
Amortization of restricted stock and release of ESOP shares	**40**	40	43
Balance at end of year	**(63)**	(96)	(121)
Executives and Directors Benefits Trust			
Balance at beginning of year	**(114)**	(145)	(68)
Revaluation to market	**19**	31	(77)
Balance at end of year	**(95)**	(114)	(145)
Accumulated Other Comprehensive Income (Loss)			
Balance at beginning of year	**(49)**	3	—
Unrealized loss on derivative instruments	**(85)**	—	—
Foreign currency translation adjustments	**9**	(49)	3
Minimum pension liability	**(73)**	(3)	—
Balance at end of year	**(198)**	(49)	3
Total Stockholders' Equity	**$6,972**	$6,365	$6,786

See accompanying notes to consolidated financial statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

millions	Years Ended December 31 2002	2001	2000
Net Income (Loss) Available to Common Stockholders	**$ 825**	$(188)	$796
Add: Preferred Stock Dividends	**6**	7	11
Net Income (Loss) Available to Common Stockholders Before Preferred Stock Dividends	**831**	(181)	807
Other Comprehensive Income (Loss), Net of Taxes			
Unrealized gain (loss) on derivative instruments:			
Cumulative effect of accounting change[1]	**—**	(5)	—
Reclassification of cumulative effect of accounting change included in net income[2]	**—**	4	—
Unrealized gain (loss) during the period[3]	**(100)**	32	—
Reclassification adjustment for (gain) loss included in net income[4]	**15**	(31)	—
Total unrealized loss on derivative instruments	**(85)**	—	—
Foreign currency translation adjustments	**9**	(49)	3
Minimum pension liability[5]	**(73)**	(3)	—
Total	**(149)**	(52)	3
Comprehensive Income (Loss)	**$ 682**	$(233)	$810

[1]net of income tax benefit (expense) of:	**$ —**	$ 3	$ —
[2]net of income tax benefit (expense) of:	**—**	(2)	—
[3]net of income tax benefit (expense) of:	**58**	(19)	—
[4]net of income tax benefit (expense) of:	**(9)**	18	—
[5]net of income tax benefit (expense) of:	**42**	1	—

See accompanying notes to consolidated financial statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

millions	Years Ended December 31 **2002**	2001	2000
Cash Flow from Operating Activities			
Net income (loss) before cumulative effect of change in accounting principle	**$ 831**	$ (176)	$ 824
Adjustments to reconcile net income (loss) before cumulative effect of change in accounting principle to net cash provided by operating activities:			
Depreciation, depletion and amortization	**1,134**	1,170	627
Amortization of goodwill	**—**	73	31
Interest expense — zero coupon debentures	**13**	13	10
Deferred income taxes	**214**	(319)	457
Impairments related to oil and gas properties	**39**	2,546	50
Other non-cash items	**(19)**	122	(124)
	2,212	3,429	1,875
(Increase) decrease in accounts receivable	**(103)**	544	(703)
Increase (decrease) in accounts payable and accrued expenses	**181**	(534)	415
Other items — net	**(94)**	(118)	(51)
Net cash provided by operating activities	**2,196**	3,321	1,536
Cash Flow from Investing Activities			
Additions to properties and equipment	**(2,388)**	(3,316)	(1,708)
Acquisition costs, net of cash acquired	**(221)**	(940)	(53)
Sales and retirements of properties and equipment	**192**	138	61
Net cash used in investing activities	**(2,417)**	(4,118)	(1,700)
Cash Flow from Financing Activities			
Additions to debt	**1,348**	2,788	345
Retirements of debt	**(987)**	(1,977)	(321)
Increase (decrease) in accounts payable, banks	**(43)**	24	56
Dividends paid	**(86)**	(64)	(50)
Retirement of preferred stock	**(2)**	(84)	—
Purchase of treasury stock	**(50)**	(116)	—
Issuance of common stock and common stock put options	**40**	49	288
Net cash provided by financing activities	**220**	620	318
Effect of Exchange Rate Changes on Cash	**(2)**	15	—
Net Increase (Decrease) in Cash and Cash Equivalents	**(3)**	(162)	154
Cash and Cash Equivalents at Beginning of Year	**37**	199	45
Cash and Cash Equivalents at End of Year	**$ 34**	$ 37	$ 199

See accompanying notes to consolidated financial statements.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2002, 2001 and 2000

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production and marketing of natural gas, crude oil, condensate and natural gas liquids (NGLs). The Company also engages in the hard minerals business through non-operated joint ventures and royalty arrangements in several coal, trona (natural soda ash) and industrial mineral mines. The terms ''Anadarko'' and ''Company'' refer to Anadarko Petroleum Corporation and its subsidiaries.

Principles of Consolidation and Use of Estimates The consolidated financial statements include the accounts of Anadarko and its subsidiaries. All significant intercompany transactions have been eliminated. The Company accounts for investments in affiliated companies (generally 20% to 50% owned) using the equity method of accounting. The financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. Certain amounts for prior periods have been reclassified to conform to the current presentation. In preparing financial statements, Management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, Management reviews its estimates, including those related to litigation, environmental liabilities, income taxes and determination of proved reserves. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Changes in Accounting Principles During 2002, the Company adopted Emerging Issues Task Force (EITF) Issue No. 02-3, ''Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.'' In accordance with EITF Issue No. 02-3, marketing sales and purchases resulting in physical settlement for prior periods have been reclassified to show net marketing margins as revenues. The marketing margins related to the Company's equity production are included in gas sales, oil and condensate sales and natural gas liquids sales and are reflected in commodity prices. The marketing margin related to purchases of third-party commodities is included in other sales. This reclassification had no effect on reported net income or cash flow.

In 2002, the Company discontinued the amortization of goodwill in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, ''Goodwill and Other Intangible Assets.'' See Note 3.

In 2002, the Company adopted the disclosure provisions of SFAS No. 148, ''Accounting for Stock-Based Compensation — Transition and Disclosure.'' See Note 2.

In 2001, the Company adopted SFAS No. 133, ''Accounting for Derivative Instruments and Hedging Activities,'' which provides guidance for accounting for derivative instruments and hedging activities. The related cumulative adjustment to net income was a decrease of $8 million ($5 million after taxes, or $0.02 per share) and the cumulative adjustment to accumulated other comprehensive income was a decrease of $8 million ($5 million after taxes) in 2001.

In 2000, the Company changed its method of accounting for the carrying value of foreign crude oil inventories from market to cost. This change was made as a result of a change in position on the carrying value of inventories communicated by the United States Securities and Exchange Commission (SEC). The related adjustment to net income was a decrease of $19 million ($17 million after taxes, or $0.09 per share) in 2000.

Properties and Equipment The Company uses the full cost method of accounting for exploration and development activities as defined by the SEC. Under this method of accounting, the costs for unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The sum of net capitalized costs and estimated future development and abandonment costs of oil and gas properties and mineral investments are amortized using the unit-of-production method. All other properties are

1. Summary of Significant Accounting Policies (Continued)

stated at original cost and are depreciated on the straight-line basis over the useful life of the assets, which ranges from three to 40 years. Properties and equipment carrying values do not purport to represent replacement or market values.

Operating fees received related to the properties in which the Company owns an interest are netted against operating expenses. Fees received in excess of costs incurred are recorded as a reduction to the full cost pool.

Costs Excluded Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent costs of investments in unproved properties and major development projects. Anadarko excludes these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the costs to be amortized (the depreciation, depletion and amortization (DD&A) pool) or a charge is made against earnings for those international operations where a reserve base has not yet been established. For international operations where a reserve base has not yet been established, an impairment requiring a charge to earnings may be indicated through evaluation of drilling results, relinquishing drilling rights or other information. Costs excluded for oil and gas properties are generally classified and evaluated as significant or individually insignificant properties.

Significant properties, comprised primarily of costs associated with domestic offshore blocks, Alaska, the Land Grant and other international areas, are individually evaluated each quarter by the Company's exploration and engineering staff. Non-producing leases are evaluated based on the progress of the Company's exploration program to date. Exploration costs are transferred to the DD&A pool upon completion of drilling individual wells. The Company has a 10 to 15 year exploration and evaluation program for the Land Grant acreage. Costs will be transferred accordingly to the DD&A pool over the length of the program. The Land Grant's mineral interests (both working and royalty interests) are owned by the Company in perpetuity. All other significant properties are evaluated over a five- to ten-year period, depending on the lease term.

Insignificant properties are comprised primarily of costs associated with onshore properties in the United States and Canada. Non-producing leases are transferred to the DD&A pool over a three- to five-year period based on the average lease period. Exploration costs are transferred to the DD&A pool upon completion of evaluation.

Capitalized Interest SFAS No. 34, ''Capitalization of Interest Cost,'' provides standards for the capitalization of interest cost as part of the historical cost of acquiring assets. Under Financial Accounting Standards Board Interpretation (FIN) No. 33, ''Applying FASB Statement No. 34 to Oil and Gas Producing Operations Accounted for by the Full Cost Method,'' costs of investments in unproved properties and major development projects, on which DD&A expense is not currently taken and on which exploration or development activities are in progress, qualify for capitalization of interest. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on debt by the amount of qualifying costs excluded. Capitalized interest cannot exceed gross interest expense. As costs excluded are transferred to the DD&A pool, the associated capitalized interest is also transferred to the DD&A pool.

Ceiling Test Under the full cost method of accounting, a ceiling test is performed each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test determines a limit, on a country-by-country basis, on the book value of oil and gas properties. The capitalized costs of proved oil and gas properties, net of accumulated DD&A and the related deferred income taxes, may not exceed the estimated future net cash flows from proved oil and gas reserves, generally using prices in effect at the end of the period held flat for the life of production, discounted at 10%, net of related tax effects, plus the cost of unevaluated properties and major development projects excluded from the costs being amortized. If capitalized costs exceed this limit, the excess is charged to expense and reflected as additional accumulated DD&A.

Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10(a)(2i), (2ii), (2iii), (3) and (4), are the estimated quantities of crude oil, natural gas, and NGLs which geological and engineering data demonstrate

1. Summary of Significant Accounting Policies (Continued)

with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Prices do not include the effect of derivative instruments entered into by the Company.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

The Company emphasizes that the volumes of reserves are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates, made by the Company's engineers, are reviewed and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in assumptions based on, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to uneconomic conditions.

Revenues The Company recognizes sales revenues based on the amount of gas, oil and NGLs sold to purchasers when delivery to the purchaser has occurred and title has transferred. This occurs when production has been delivered to a pipeline or a tanker lifting has occurred. The Company follows the sales method of accounting for production imbalances. If the Company's excess sales of production volumes for a well exceed the estimated remaining recoverable reserves of the well, a liability is recorded. No receivables are recorded for those wells on which the Company has taken less than its ownership share of production. Marketing margins related to the Company's equity production are included in gas sales, oil and condensate sales and natural gas liquids sales and are reflected in commodity prices. The marketing margin related to purchases of third-party commodities is included in other sales.

Derivative Instruments Anadarko uses derivative instruments for various risk management purposes. Effective January 2001, derivative instruments utilized to manage or reduce commodity price risk related to the Company's equity production are accounted for under the provisions of SFAS No. 133. Under this statement, all derivatives are carried on the balance sheet at fair value. Realized gains and losses are recognized in sales when the underlying physical gas and oil production is sold. Accordingly, realized derivative gains and losses are generally offset by similar changes in the realized value of the underlying physical gas and oil production. Realized derivative gains and losses are reflected in the average sales price of the physical gas and oil production.

Accounting for unrealized gains and losses is dependent on whether the derivative instruments have been designated and qualify as part of a hedging relationship. Derivative instruments may be designated as a hedge of exposure to changes in fair values, cash flows or foreign currencies, if certain conditions are met. Unrealized gains and losses on derivative instruments that do not meet the conditions to qualify for hedge accounting are recognized currently in other (income) expense.

If the hedged exposure is to change in fair value, the gains and losses on the derivative instrument, as well as the offsetting losses and gains on the hedged item, are recognized currently in earnings. Consequently, if gains and losses on the derivative instrument and the related hedge item do not completely offset, the difference (i.e., ineffective portion of the hedge) is recognized currently in earnings.

1. Summary of Significant Accounting Policies (Continued)

If the hedged exposure is a cash flow exposure, the effective portion of the gains and losses on the derivative instrument is reported as a component of accumulated other comprehensive income and reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The ineffective portion of the gains and losses from the derivative instrument, if any, as well as any amounts excluded from the assessment of the cash flow hedges' effectiveness are recognized currently in other (income) expense.

Derivative instruments, as well as physical delivery purchase and sale contracts, utilized in the Company's energy trading activities and in the management of price risk associated with the Company's firm transportation keep-whole commitment were accounted for under the mark-to-market accounting method pursuant to EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." Under this method, the derivatives and physical delivery contracts are revalued in each accounting period and unrealized gains and losses are recorded in the statement of income and carried as assets or liabilities on the balance sheet. EITF Issue No. 98-10 was rescinded in October 2002. See New Accounting Principles.

The Company's derivative instruments associated with the marketing and trading activities are generally either exchange traded or valued by reference to a commodity that is traded in a liquid market. Valuation is determined by reference to readily available public data. Option valuations are based on the Black-Scholes option pricing model and verified against third-party quotations. The fair value of the short-term portion of the firm transportation keep-whole agreement is calculated with quoted natural gas basis prices, while the fair value of the long-term portion is estimated based on historical natural gas basis prices, discounted at 10% per year. See Note 8.

Prior to 2001, derivative instruments utilized to manage or reduce commodity price risk related to the Company's equity production (with the exception of net written options) were accounted for under the hedge or deferral method of accounting. Under this method, realized gains and losses and option premiums were recognized in the statement of income when the underlying physical oil and gas production was sold. Accordingly, realized gains and losses were generally offset by similar changes in the realized prices of the underlying physical oil and gas production. Realized derivative gains and losses were reflected in the average sales price of the physical oil and gas production. Margin deposits, deferred realized gains and losses and premiums were included in other current assets or liabilities. Unrealized gains and losses were not recorded.

Inventories Materials and supplies and company-produced commodity inventories are stated at the lower of average cost or market. Prior to October 25, 2002, inventories consisting of commodities purchased from third parties utilized in the Company's energy trading activities were carried at fair value. Company-produced commodities, when sold from inventory, were charged to expense using the average-cost method. Commodities purchased from third parties, when sold from inventory, were charged to expense using market price. Due to the recission of EITF Issue No. 98-10, commodities purchased from third parties after October 25, 2002 are accounted for at the lower of average-cost or market. See New Accounting Principles.

Goodwill Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired and liabilities assumed in the merger with Union Pacific Resources Group Inc., subsequently renamed Anadarko Holding Company (Anadarko Holding), and the acquisition of Berkley Petroleum Corp. (Berkley). For 2000 and 2001, goodwill was amortized on a straight-line basis over 20 years. Prior to the adoption of SFAS No. 142, the Company assessed the recoverability of goodwill by determining whether the amortization of the goodwill balance over its remaining life could be recovered through undiscounted future operating cash flows of the acquired operations. The amount of goodwill impairment, if any, would have been measured based on projected discounted future operating cash flows using a discount rate reflecting the Company's average cost of funds. In accordance with the adoption of SFAS No. 142, the Company assesses the carrying amount of goodwill by testing the goodwill for impairment. The impairment test requires allocating goodwill and all other assets and liabilities to reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the

1. Summary of Significant Accounting Policies (Continued)

goodwill is written down to the implied fair value of the goodwill through a charge to expense. Also under SFAS No. 142, goodwill is no longer amortized effective January 2002. See Note 3.

Legal Contingencies The Company is subject to legal proceedings, claims and liabilities which arise in the ordinary course of its business. The Company accrues for losses associated with legal claims when such losses are probable and can be reasonably estimated. These accruals are adjusted as further information develops or circumstances change. See Note 19.

Environmental Contingencies The Company accrues for losses associated with environmental remediation obligations when such losses are probable and can be reasonably estimated. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the time of the completion of the remedial feasibility study. These accruals are adjusted as further information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. See Note 19.

Income Taxes The Company files various United States federal, state and foreign income tax returns. Deferred federal, state and foreign income taxes are provided on all significant temporary differences, except for those essentially permanent in duration, between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases.

Cash Equivalents The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Stock-Based Compensation The Company accounts for stock-based compensation under the intrinsic value method. Under this method, the Company records no compensation expense for stock options granted to employees or directors when the exercise price of options granted is equal to or above the fair market value of Anadarko's common stock on the date of grant. See Notes 2 and 10.

Earnings Per Share The Company's basic earnings (loss) per share (EPS) amounts have been computed based on the average number of shares of common stock outstanding for the period. Diluted EPS amounts include the effect of the Company's outstanding stock options and performance-based stock awards under the treasury stock method and outstanding put options under the reverse treasury stock method, if including such equity instruments is dilutive. Diluted EPS amounts also include the net effect of the Company's convertible debentures and Zero Yield Puttable Contingent Debt Securities (ZYP-CODES) assuming the conversions occurred at the beginning of the year or the date of issuance, if including such potential common shares is dilutive. See Note 10.

New Accounting Principles SFAS No. 143, ''Accounting for Asset Retirement Obligations,'' requires the fair value of a liability for an asset retirement obligation to be recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset and is effective for the Company in 2003. The Company has evaluated the impact of SFAS No. 143 and expects to record an after tax gain of between $35 million and $55 million as a cumulative effect of change in accounting principle. Additionally, the Company expects to record an asset retirement obligation liability of between $220 million and $330 million and an increase to net properties and equipment of between $270 million and $410 million. The application of SFAS No. 143 in 2003 and future years will result in the recognition of accretion expense related to the discounted liability for the asset retirement obligation and should not have a material impact on the Company's DD&A rate. There will be no impact on the Company's cash flow as a result of adopting SFAS No. 143.

SFAS No. 145, ''Rescission of FASB Statements No. 4, 44 and 64,'' was issued in April 2002. SFAS No. 145 provides guidance for income statement classification of gains and losses on extinguishment of debt and accounting for certain lease modifications that have economic effects that are similar to sale-leaseback

1. Summary of Significant Accounting Policies (Continued)

transactions. SFAS No. 145 is effective for the Company in 2003. The Company has evaluated the impact of SFAS No. 145 and does not expect adoption to materially affect the consolidated financial statements.

SFAS No. 146, ''Accounting for Costs Associated with Exit or Disposal Activities,'' was issued in June 2002. SFAS No. 146 addresses significant issues regarding the recognition, measurement and reporting of costs that are associated with exit and disposal activities, including restructuring activities. SFAS No. 146 is effective for the Company in 2003. The Company has evaluated the impact of SFAS No. 146 and does not expect adoption to materially affect the consolidated financial statements.

SFAS No. 148 was issued in December 2002. SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation and amends the disclosure requirements of SFAS No. 123, ''Accounting for Stock-Based Compensation.'' The Company adopted the disclosure provisions in 2002 and plans to voluntarily change in 2003 to the fair value based method of accounting for stock-based employee compensation using the prospective method described in SFAS No. 148.

EITF Issue No. 98-10 was rescinded in 2002. As a result, mark-to-market accounting is precluded for commodity inventories and energy trading contracts that are not derivatives pursuant to SFAS No. 133. The recission of EITF Issue No. 98-10 is effective for commodity inventories acquired and contracts entered into subsequent to October 25, 2002 and for all commodity inventories held and contracts in effect on January 1, 2003. Substantially all of the Company's physical delivery energy trading contracts are considered to be derivatives pursuant to SFAS No. 133. Therefore, the recission of EITF Issue No. 98-10 did not have a significant impact on the accounting for energy trading contracts as those contracts continue to be marked to market in accordance with SFAS No. 133.

FIN No. 45, ''Guarantor's Accounting and Disclosure Requirements for Guarantees,'' was issued in November 2002. This interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. It also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of a guarantee for the obligations the guarantor has undertaken in issuing that guarantee. The Company has adopted the disclosure provisions in 2002. See Notes 17 and 19. The initial recognition and initial measurement provisions are applicable to guarantees issued or modified in 2003 and are not expected to have a material impact on the Company's consolidated financial statements.

FIN No. 46, ''Consolidation of Variable Interest Entities,'' was issued in January 2003. FIN No. 46 addresses consolidation by business enterprises of variable interest entities. It applies immediately to variable interest entities created after January 31, 2003. For entities created prior to this date, FIN No. 46 is effective for the third quarter 2003. The Company is evaluating the impact of FIN No. 46 on accounting for and the possible restructuring of its synthetic leases. See Note 17. If the synthetic leases are not restructured prior to July 2003, the current synthetic lease related entities will be consolidated with the Company. The Company believes this would increase properties and equipment by $220 million with a corresponding increase in long-term debt of $232 million. Any impact on the income statement would be a cumulative effect adjustment equal to the difference between the fair value of the assets and liabilities recorded related to the consolidated variable interest entities and is not expected to be material.

2. Stock-Based Compensation

SFAS No. 123 defines a fair value method of accounting for an employee stock option or similar equity instrument. SFAS No. 123 allows an entity to continue to measure compensation costs for these plans using Accounting Principles Board (APB) Opinion No. 25. Anadarko applies APB No. 25 in accounting for employee stock compensation plans whereby no compensation expense is recognized for stock options granted with an exercise price equal to the market value of Anadarko stock on the date of grant. If compensation expense for the

2. Stock-Based Compensation (Continued)

Company's stock option plans had been determined using the fair-value method in SFAS No. 123, the Company's net income and EPS would have been as shown in the pro forma amounts below:

millions except per share amounts	**2002**	2001	2000
Net income (loss) available to common stockholders before cumulative effect of change in accounting principle	**$ 825**	$ (183)	$ 813
Add: Stock-based employee compensation expense included in net income, after taxes	**9**	10	21
Deduct: Total stock-based employee compensation expense determined under the fair value method, after taxes	**(32)**	(52)	(58)
Pro forma net income (loss)	**$ 802**	$ (225)	$ 776
Basic EPS - as reported	**$3.32**	$(0.73)	$4.42
Basic EPS - pro forma	**$3.23**	$(0.90)	$4.22
Diluted EPS - as reported	**$3.21**	$(0.73)	$4.25
Diluted EPS - pro forma	**$3.13**	$(0.90)	$4.05

The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

	2002	2001	2000
Expected option life – years	**5.29**	4.14	4.35
Risk-free interest rate	**3.73%**	4.48%	6.10%
Dividend yield	**0.51%**	0.46%	0.50%
Volatility	**41.66%**	43.79%	39.17%

3. Goodwill

SFAS No. 142 required discontinuing amortization of goodwill after year-end 2001 and requires that goodwill be tested for impairment. The impairment test requires allocating goodwill and all other assets and liabilities to business levels referred to as reporting units. The fair value of each reporting unit that has goodwill is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value (including goodwill) then a second test is performed to determine the amount of the impairment.

If the second test is necessary, the fair value of the reporting unit's individual assets and liabilities is deducted from the fair value of the reporting unit. This difference represents the implied fair value of goodwill, which is compared to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the amount of the impairment.

The goodwill impairment test is performed annually, and also at interim dates upon the occurrence of significant events. Significant events include: a significant adverse change in legal factors or business climate; an adverse action or assessment by a regulator; a more-likely-than-not expectation that a reporting unit or significant portion of a reporting unit will be sold; significant adverse trends in current and future oil and gas prices; nationalization of any of the Company's oil and gas properties; or, significant increases in a reporting unit's carrying value relative to its fair value.

In January 2002, the Company discontinued the amortization of goodwill in accordance with SFAS No. 142. The transitional goodwill impairment test as of January 2002 was performed and no goodwill impairment was indicated. The annual goodwill impairment test was performed as of January 2003 and no goodwill impairment was indicated. The following table shows the effect of the elimination of amortization of goodwill on the

3. Goodwill (Continued)

Company's net income and net income per share as if SFAS No. 142 had been in effect in prior periods. Prior to 2000, the Company had no goodwill or goodwill amortization recorded.

millions except per share amounts	2001	2000
Net income (loss)	$ (188)	$ 796
Add: Goodwill amortization	73	31
Adjusted net income (loss)	$ (115)	$ 827
Earnings (loss) per share — basic	$(0.75)	$4.32
Goodwill amortization per share — basic	0.29	0.17
Adjusted earnings (loss) per share — basic	$(0.46)	$4.49
Earnings (loss) per share — diluted	$(0.75)	$4.16
Goodwill amortization per share — diluted	0.29	0.16
Adjusted earnings (loss) per share — diluted	$(0.46)	$4.32

The changes in goodwill since December 31, 2001 are due primarily to changes in foreign currency exchange rates. Future changes in goodwill may result from, among other things, changes in foreign currency exchange rates, changes in deferred income tax liabilities related to acquisitions, divestitures, impairments or future acquisitions.

4. Merger and Acquisitions

In July 2000, the Company merged with Union Pacific Resources Group Inc., subsequently renamed Anadarko Holding Company. Each share of common stock of Anadarko Holding issued and outstanding was converted into 0.455 shares of Anadarko common stock. The merger was a tax-free reorganization and accounted for as a purchase business combination under generally accepted accounting principles. Under this method of accounting, the Company's historical operating results for periods prior to the merger are the same as Anadarko's historical operating results. At the date of the merger, the assets and liabilities of Anadarko remained based upon their historical costs, and the assets and liabilities of Anadarko Holding were recorded at their estimated fair market values.

Had the Anadarko Holding merger transaction occurred on January 1, 2000, unaudited pro forma results of the Company would have included revenues of $4.1 billion and net income available to common stockholders of $1.1 billion ($4.45 per share — basic and $4.30 per share — diluted) for the year ended December 31, 2000. The pro forma results for 2000 are a result of combining the statement of income of Anadarko with the statement of income of Anadarko Holding adjusted for (1) certain costs that Anadarko Holding had expensed under the successful efforts method of accounting that are capitalized under the full cost method of accounting; (2) DD&A expense of Anadarko Holding calculated in accordance with the full cost method of accounting applied to the adjusted basis of the properties acquired using the purchase method of accounting; (3) decreases to interest expense for the capitalization of interest on significant investments in unevaluated properties and major development projects and partly offset by the revaluation of Anadarko Holding debt under the purchase method of accounting, including the elimination of historical debt issuance amortization costs; (4) issuance of Anadarko common stock and stock options pursuant to the merger agreement; and (5) the related income tax effects of these adjustments based on the applicable statutory tax rates. It should be noted that the pro forma results do not include any merger expenses and are not necessarily indicative of actual results.

In March 2001, Anadarko acquired Canadian based Berkley for C$11.40 per share for an aggregate equity value of $779 million plus the assumption of $236 million of debt. Goodwill recorded related to the Berkley acquisition was $245 million.

In August 2001, the Company completed the acquisition of Gulfstream Resources Canada Limited (Gulfstream). The Gulfstream shares were purchased for C$2.65 per share, for a total value of $118 million plus the assumption of $10 million of debt.

4. Merger and Acquisitions (Continued)

In December 2002, the Company completed the acquisition of Howell Corporation (Howell) in which the common stockholders of Howell received $20.75 per share and holders of Howell's $3.50 convertible preferred stock received $76.15 per share. The value of the acquisition was $258 million, including the assumption of $53 million of debt.

The unaudited pro forma results of operations including the acquisition transactions in 2002 and 2001 would not have been significantly different from actual results for 2002 and 2001.

Merger costs related to corporate acquisitions of $14 million, $45 million and $67 million for the years ended December 31, 2002, 2001 and 2000, respectively, were recorded as administrative and general expense. These costs relate primarily to the issuance of stock for retention of employees, deferred compensation, transition, integration, hiring and relocation costs, vesting of restricted stock and stock options and retention bonuses.

5. Inventories

The major classes of inventories, which are included in other current assets, are as follows:

millions	**2002**	2001
Materials and supplies	**$ 75**	$ 61
Natural gas	**16**	18
Crude oil	**15**	22
Total	**$106**	$101

6. Properties and Equipment

A summary of the original cost of properties and equipment by classification follows:

millions	**2002**	2001
Oil and gas properties	**$20,467**	$18,047
Mineral properties	**1,211**	1,212
Gathering facilities	**310**	295
General properties	**607**	534
Total	**$22,595**	$20,088

Oil and gas properties include costs of $3.1 billion and $3.6 billion at December 31, 2002 and 2001, respectively, which were excluded from capitalized costs being amortized. These amounts represent costs associated with unevaluated properties and major development projects. At December 31, 2002 and 2001, the Company's investment in countries where reserves have not been established was $63 million and $53 million, respectively.

During 2002, 2001 and 2000, the Company made provisions for impairments of U.S. and international properties of $39 million, $2.5 billion and $50 million, respectively, which were related to oil and gas properties. In 2002, the Company recorded international impairments of $39 million in Congo, Oman, Australia and Tunisia primarily due to unsuccessful exploration activities. As a result of low oil and gas prices at September 30, 2001, Anadarko's capitalized costs of oil and gas properties primarily in the United States, Canada and Argentina exceeded the ceiling limitation and the Company recorded a $2.5 billion ($1.6 billion after taxes) non-cash write-down in the third quarter of 2001. The pre-tax write-down is reflected as additional accumulated DD&A in the accompanying balance sheet. The remaining 2001 impairment of $18 million related to unsuccessful exploration activities in the United Kingdom and Ghana. In 2000, the Company recorded international impairments of $50 million for unsuccessful exploration activities in the United Kingdom, Tunisia and other international locations.

6. Properties and Equipment (Continued)

Total interest costs incurred during 2002, 2001 and 2000 were $358 million, $301 million and $193 million, respectively. Of these amounts, the Company capitalized $155 million, $209 million and $100 million during 2002, 2001 and 2000, respectively. Capitalized interest is included as part of the cost of oil and gas properties. The interest rates for capitalization are based on the Company's weighted average cost of borrowings used to finance the expenditures applied to costs excluded.

In addition to capitalized interest, the Company also capitalized internal costs of $196 million, $178 million and $124 million during 2002, 2001 and 2000, respectively. These internal costs were directly related to exploration and development activities and are included as part of the cost of oil and gas properties.

7. Debt

A summary of debt follows:

	2002		2001	
millions	**Principal**	**Carrying Value**	Principal	Carrying Value
Notes Payable, Banks*	**$ 44**	**$ 44**	$ 228	$ 228
Commercial Paper*	**181**	**181**	226	226
Long-term Portion of Capital Lease	**7**	**7**	9	9
6.8% Debentures due 2002	**—**	**—**	88	88
6¾% Notes due 2003	**73**	**73**	73	73
5⅞% Notes due 2003	**83**	**83**	83	83
6.5% Notes due 2005	**170**	**166**	170	164
7.375% Debentures due 2006	**88**	**87**	88	87
7% Notes due 2006	**174**	**171**	174	170
5⅜% Notes due 2007	**650**	**647**	—	—
6.75% Notes due 2008	**116**	**111**	116	110
7.8% Debentures due 2008	**11**	**11**	11	11
7.3% Notes due 2009	**85**	**83**	85	82
6¾% Notes due 2011	**950**	**912**	950	910
6⅛% Notes due 2012	**400**	**395**	—	—
5% Notes due 2012	**300**	**297**	—	—
7.05% Debentures due 2018	**114**	**105**	114	105
Zero Coupon Convertible Debentures due 2020	**380**	**380**	367	367
Zero Yield Puttable Contingent Debt Securities due 2021	**30**	**30**	650	650
7.5% Debentures due 2026	**112**	**106**	112	105
7% Debentures due 2027	**54**	**54**	54	54
6.625% Debentures due 2028	**17**	**17**	17	17
7.15% Debentures due 2028	**235**	**212**	235	212
7.20% Debentures due 2029	**135**	**135**	135	135
7.95% Debentures due 2029	**117**	**117**	117	117
7½% Notes due 2031	**900**	**862**	900	862
7.73% Debentures due 2096	**61**	**61**	61	61
7¼% Debentures due 2096	**49**	**49**	49	49
7.5% Debentures due 2096	**83**	**75**	83	75
Total debt	**$5,619**	**5,471**	$5,195	5,050
Less current portion		**300**		412
Total long-term debt		**$5,171**		$4,638

* The average rates in effect at December 31, 2002 and 2001 were 1.57% and 2.55%, respectively, for Notes Payable, Banks. The average rates in effect at December 31, 2002 and 2001 were 1.88% and 2.59%, respectively, for Commercial Paper.

7. Debt (Continued)

The Company recorded debt discount of $11 million, $40 million and $116 million in 2002, 2001 and 2000, respectively, as a result of debt issuances, financial restructuring and corporate acquisitions. The unamortized debt discount of $148 million and $145 million as of December 31, 2002 and 2001, respectively, will be amortized over the terms of the debt issues.

Anadarko has noncommitted lines of credit from several banks. The general provisions of these lines of credit provide for Anadarko to borrow funds for terms and rates offered from time to time by the banks. There are no fees associated with these lines of credit.

The Company has commercial paper programs that allow Anadarko to borrow funds, at rates as offered, by issuing notes to investors for terms of up to one year.

At December 31, 2002, $761 million of notes, debentures and securities will mature or may be put to Anadarko within the next twelve months. In accordance with SFAS No. 6, ''Classification of Short-term Obligations Expected to be Refinanced,'' $461 million of this amount is classified as long-term debt, since Anadarko has the intent and ability to refinance this debt under the terms of Anadarko's Bank Credit Agreements.

In March 2000, Anadarko issued $345 million of Zero Coupon Convertible Debentures due March 2020, with a face value at maturity of $690 million. The debentures were issued at a discount and accrue interest at 3.50% annually until reaching face value at maturity; however, interest will not be paid prior to maturity. The debentures were issued at an initial conversion premium of 40% and are convertible into Anadarko common stock at the option of the holder at any time at a fixed conversion rate of 11.6288 shares of common stock per debenture. Holders have the right to require Anadarko to repurchase their debentures at a specified price in March 2003, 2008 and 2013. The debentures are redeemable at the option of Anadarko after three years. The net proceeds from the offering were used to repay floating interest rate debt.

In March 2001, Anadarko issued $650 million of ZYP-CODES due 2021 to qualified institutional buyers under Rule 144A and non-U.S. persons under Regulation S. The debt securities were priced with a zero coupon, zero yield to maturity and a conversion premium of 38%. The proceeds from the debt securities, net of $6 million of debt offering expenses, were used initially to finance costs associated with the acquisition of Berkley. In March 2002, ZYP-CODES in the amount of $620 million were put to the Company for repayment and were paid in cash. The ZYP-CODES are convertible into Anadarko common stock at the option of the holder at any time at a fixed conversion rate of 9.9285 shares of common stock per $1,000 principal amount of ZYP-CODES. Holders of the remaining ZYP-CODES have the right to require Anadarko to purchase all or a portion of their ZYP-CODES in March 2004, 2006, 2011 or 2016, at $1,000 per ZYP-CODES.

In April 2001, Anadarko Finance Company, a wholly-owned finance subsidiary of Anadarko, issued $1.3 billion in notes to qualified institutional buyers under Rule 144A and non-U.S. persons under Regulation S. This issuance was made up of $400 million of 6¾% Notes due 2011 and $900 million of 7½% Notes due 2031. In May 2001, Anadarko Finance Company issued an additional $550 million of 6¾% Notes due 2011, bringing the 6¾% Notes to an aggregate total of $950 million. The notes are fully and unconditionally guaranteed by Anadarko. The proceeds from the notes, net of $11 million in discounts, were used as part of an exchange of securities for other Anadarko debt. The intercompany debt resulting from these transactions is of a long-term investment nature; therefore, net foreign currency translation gains of $19 million and losses of $55 million for 2002 and 2001, respectively, were recorded as a component of other comprehensive income.

In February 2002, the Company issued $650 million principal amount of 5⅜% Notes due 2007. In March 2002, the Company issued $400 million principal amount of 6⅛% Notes due 2012. The net proceeds from these issuances were used to reduce floating rate debt and to fund a portion of the ZYP-CODES put to the Company for repayment in March 2002.

In April 2002, Anadarko filed a shelf registration statement with the SEC that permits the issuance of up to $1 billion in debt securities, preferred stock, preferred securities, depositary shares, common stock, warrants, purchase contracts and purchase units. Net proceeds, terms and pricing of the offerings of securities issued under the shelf registration statement will be determined at the time of the offerings.

7. Debt (Continued)

In September 2002, Anadarko issued $300 million principal amount of 5% Notes due 2012. The net proceeds from the issuance were used to reduce floating rate debt. These notes were issued under the shelf registration statement filed in April 2002.

In October 2002, the Company entered into a 364-Day Revolving Credit Agreement. The agreement provides for $225 million principal amount and expires in 2003. Also in October 2002, Anadarko Canada Corporation (Anadarko Canada), a wholly-owned subsidiary of Anadarko, entered into a 364-Day Canadian Credit Agreement. The agreement provides for $300 million principal amount and expires in 2003. The agreement is fully and unconditionally guaranteed by Anadarko. Interest rates for these bank commitments are based on either the prime rate, Fed Funds rate, London interbank borrowing rate or Bankers' Acceptance rate. In addition, the Company has a Revolving Credit Agreement that provides for $225 million principal amount and expires in 2004. As of December 31, 2002, the Company had no outstanding borrowings under these bank credit agreements.

At December 31, 2002 and 2001, a Canadian subsidiary had $98 million and $187 million, respectively, outstanding fixed-rate notes and debentures denominated in U.S. dollars. During 2002, 2001 and 2000, the Company recognized $5 million of gains, $25 million of losses and $8 million of losses, respectively, before taxes associated with the remeasurement of this debt.

Total sinking fund and installment payments related to debt for the five years ending December 31, 2007 are shown below. The payments related to a portion of the Commercial Paper are included in the amounts shown in a manner consistent with the terms for repayment of Anadarko's bank credit agreements.

millions	
2003*	$300
2004**	30
2005	170
2006	262
2007	650

* Holders of the Zero Coupon Convertible Debentures due 2020 had the right to put the debentures to the Company in March 2003 at the accrued value of $383 million. This debt instrument has not been reflected in the table above.

** Holders of the ZYP-CODES due 2021 may put the remaining $30 million principal amount of the ZYP-CODES to the Company in 2004.

8. Financial Instruments

The following information provides the carrying value and estimated fair value of the Company's financial instruments:

millions	Carrying Amount	Fair Value
2002		
Cash and cash equivalents	**$ 34**	**$ 34**
Total debt	**5,471**	**6,112**
Commodity derivative instruments (including firm transportation keep-whole agreement)		
Asset	**85**	**85**
Liability	**(288)**	**(288)**
Foreign currency derivative instruments	**(8)**	**(8)**
2001		
Cash and cash equivalents	$ 37	$ 37
Total debt	5,050	5,170
Commodity derivative instruments (including firm transportation keep-whole agreement)		
Asset	105	105
Liability	(217)	(217)
Foreign currency derivative instruments	(10)	(10)

Cash and Cash Equivalents The carrying amount reported on the balance sheet approximates fair value.

Debt The fair value of debt at December 31, 2002 and 2001 is the value the Company would have to pay to retire the debt, including any premium or discount to the debt holder for the differential between stated interest rate and year-end market rate. The fair values are based on quoted market prices and, where such quotes were not available, on the average rate in effect at year-end.

Commodity Derivative Instruments The Company is exposed to price risk from changing commodity prices. Management believes it is prudent to minimize the variability in cash flows on a portion of its oil and gas production. To meet this objective, the Company enters into various types of commodity derivative instruments to manage fluctuations in cash flows resulting from changing commodity prices. The Company also uses fixed price physical delivery sales contracts to accomplish this objective. The types of instruments utilized by the Company may include futures, swaps and options.

Anadarko also enters into commodity derivative instruments (options, futures and swaps) for trading purposes with the objective of generating profits from exposure to changes in the market price of natural gas and crude oil. Commodity derivative instruments are also used to meet customers' pricing requirements while achieving a price structure consistent with the Company's overall pricing strategy. In addition, the Company has used swap agreements to reduce exposure to losses on its firm transportation keep-whole commitment with Duke Energy Field Services, Inc. (Duke). Essentially all of the derivatives used for trading purposes have a term of less than one year, with most having a term of less than three months.

Futures contracts are generally used to fix the price of expected future oil and gas sales at major industry trading locations; e.g., Henry Hub, Louisiana for gas and Cushing, Oklahoma for oil. Settlements of futures contracts are guaranteed by the New York Mercantile Exchange (NYMEX) or the International Petroleum Exchange and have nominal credit risk. Swap agreements are generally used to fix or float the price of oil and gas at the Company's market locations. Swap agreements are also used to fix the price differential between the price of gas at Henry Hub and various other market locations. Swap agreements expose the Company to credit risk to

8. Financial Instruments (Continued)

the extent the counter-party is unable to meet its settlement commitment. The Company carefully monitors the creditworthiness of each counter-party. In addition, the Company routinely exercises its contractual right to net realized gains against realized losses in settling with its swap counterparties. Options are generally used to fix a floor and a ceiling price (a collar) for the Company's expected future oil and gas sales. The Company buys and sells options through exchanges as well as in the over the counter market.

Cash Flow Hedges At December 31, 2002, the Company had option and swap contracts in place to fix floor and ceiling prices on a portion of expected future sales of equity gas and oil production. The Company has option contracts to hedge its exposure to the variability in future cash flows associated with sales of oil production that extend through December 2003 and associated with sales of gas production that extend through December 2005. Swap agreements to hedge the Company's exposure to the variability in future cash flows associated with sales of oil production extend through December 2004 and associated with sales of gas production that extend through December 2004. As of December 31, 2002 and 2001, the Company had a net unrealized loss of $128 million before taxes, or $81 million after taxes, and a net unrealized gain of $7 million before taxes (gains of $9 million and losses of $2 million), or $4 million after taxes, respectively, on derivative instruments entered into to hedge production recorded in accumulated other comprehensive income. Other income for 2002 and 2001 included $33 million of net losses and $18 million of net gains, respectively, related to derivative instruments. These gains and losses were primarily due to recognition of unrealized gains and losses related to those hedges that did not qualify for hedge accounting and hedge ineffectiveness. Approximately $61 million after taxes of net losses in the accumulated other comprehensive income balance as of December 31, 2002 are expected to be reclassified into gas and oil sales during 2003 as the hedged transactions occur.

8. Financial Instruments (Continued)

As of December 31, 2002 and 2001, the Company had the following volumes under derivative contracts related to its oil and gas producing activities (non-trading activity). The difference between the fair values in the table and the unrealized gain (loss) before income taxes recognized in accumulated other comprehensive income is due to premiums, recognition of unrealized gains and losses on certain derivatives that did not qualify for hedge accounting, hedge ineffectiveness and foreign currency hedges.

December 31, 2002

Production Period	Instrument Type*	Volumes	Average Price	Net Fair Value Asset (Liability) *millions*
Natural Gas		(million MMBtu)	($ per MMBtu)	
2003	Swaps**	69	3.89	$ (46)
2003	3-way collars**	107	2.61-3.69-4.72	(29)
2004	Swaps**	70	3.88	(26)
2004	3-way collars**	58	2.48-3.47-4.91	(10)
2005	3-way collars**	3	2.20-3.00-5.05	—
2003	Swaps	4	3.88	(1)
2003	Calls sold	7	3.22	(3)
2003	Calls purchased	10	3.38	4
2003	2-way collars	2	3.00-5.00	(1)
2003	3-way collars	5	2.34-3.30-4.58	(2)
2004	Swaps	4	3.88	(1)
2004	Calls sold	1	2.98	—
2004	Calls purchased	1	2.98	—
2004	2-way collars	2	3.00-5.00	(1)
2004	3-way collars	3	2.20-3.00-4.60	(1)
2005	2-way collars	2	3.00-5.00	—
2005	3-way collars	3	2.20-3.00-4.60	(1)
	Total			$(118)
Crude Oil		(MMBbls)	($ per barrel)	
2003	Swaps**	5	25.31	$ (9)
2003	2-way collars**	—	22.30-23.32	(2)
2003	3-way collars**	16	18.91-24.31-27.62	(19)
2004	Swaps**	3	23.09	(1)
2003	3-way collars	3	17.00-21.00-26.13	(5)
2003	Calls sold	13	27.47	(23)
2003	Calls purchased	13	27.47	23
	Total			$ (36)

8. Financial Instruments (Continued)

December 31, 2001

Production Period	Instrument Type*	Volumes	Average Price	Net Fair Value Asset (Liability) *millions*
Natural Gas		(million MMBtu)	($ per MMBtu)	
2002	2-way collars**	2	3.00-5.00	$ 1
2002	3-way collars**	7	2.20-3.00-4.83	2
2003	2-way collars**	2	3.00-5.00	1
2003	3-way collars**	7	2.20-3.00-4.83	1
2004	2-way collars**	2	3.00-5.00	1
2004	3-way collars**	7	2.20-3.00-4.83	1
2005	2-way collars**	2	3.00-5.00	1
2005	3-way collars**	7	2.20-3.00-4.83	1
2002	Calls sold	10	3.66	2
2002	Calls purchased	5	3.50	—
2003	Calls sold	7	3.18	(2)
2003	Calls purchased	10	4.12	2
2004	Calls sold	1	2.95	—
2004	Calls purchased	1	2.95	—
	Total			$ 11
Crude Oil		(MMBbls)	($ per barrel)	
2002	Swaps**	1	25.56	$ 2
2002	3-way collars**	3	19.11-23.33-30.51	6
	Total			$ 8

MMBtu — million British thermal units
MMBbls — million barrels

* A 2-way collar is a combination of options, a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract. A 3-way collar is a combination of options, a sold call, a purchased put and a sold put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price the Company will receive for the volumes under contract.

** Qualifies for hedge accounting.

8. Financial Instruments (Continued)

Fair Value Hedge The Company had a swap agreement in place to convert a gas contract from a fixed price to a market sensitive price. The term of this swap agreement, as well as the underlying gas contract, expired October 31, 2001.

Trading Activities As of December 31, 2002 and 2001, the Company had the following volumes under derivative contracts related to its trading activity:

December 31, 2002

Production Period	Instrument Type	Volumes	Average Price	Net Fair Value Asset (Liability) *millions*
Natural Gas		(million MMBtu)	($ per MMBtu)	
2003	Futures sold	33	4.29	$ 18
2003	Futures purchased	28	4.15	(21)
2003	Swaps	80	4.25	26
2003	Calls sold	11	4.83	(1)
2003	Calls purchased	10	4.79	1
2003	Puts sold	3	3.77	—
2003	Puts purchased	4	3.66	—
2004	Futures sold	1	4.50	—
2004	Futures purchased	1	3.97	(1)
2004	Swaps	8	4.01	1
2005	Swaps	1	3.97	—
2006	Swaps	1	3.87	—
	Total			$ 23
Crude Oil		(MMBbls)	($ per barrel)	
2003	Futures sold	1	27.49	$ —
2003	Futures purchased	1	26.91	1
	Total			$ 1

8. Financial Instruments (Continued)

December 31, 2001

Production Period	Instrument Type	Volumes	Average Price	Net Fair Value Asset (Liability) *millions*
Natural Gas		(million MMBtu)	($ per MMBtu)	
2002	Futures sold	24	3.34	$ 18
2002	Futures purchased	22	3.50	(21)
2002	Swaps	72	3.20	(42)
2002	Calls sold	8	3.07	1
2002	Calls purchased	13	4.09	1
2002	Puts sold	8	3.25	(7)
2002	Puts purchased	1	2.58	—
2003	Futures sold	1	3.51	—
2003	Futures purchased	1	3.36	—
2003	Swaps	12	3.12	—
	Total			$(50)
Crude Oil		(MMBbls)	($ per barrel)	
2002	Futures sold	3	19.80	$ (1)
2002	Futures purchased	1	20.05	2
2002	Swaps	1	21.77	—
2002	Calls sold	1	29.50	—
	Total			$ 1

Firm Transportation Keep-whole Agreement Anadarko Holding was a party to several long-term firm gas transportation agreements that supported its gas marketing program within its gathering, processing and marketing (GPM) business segment, which was sold in 1999 to Duke. Most of the GPM's firm long-term transportation contracts were transferred to Duke in the GPM disposition. One contract was retained, but is managed and operated by Duke. Anadarko is not responsible for the operations of the contracts and does not utilize the associated transportation assets to transport the Company's natural gas. As part of the GPM disposition, Anadarko Holding agreed to pay Duke if transportation market values fall below the fixed contract transportation rates, while Duke will pay Anadarko Holding if the transportation market values exceed the contract transportation rates (keep-whole agreement). This keep-whole agreement will be in effect until the earlier of each contract's expiration date or February 2009. The Company may periodically use derivative instruments to reduce its exposure under the Duke keep-whole agreement to potential decreases in future transportation market values. While derivatives are intended to reduce the Company's exposure to declines in transportation market rates, they also limit the potential to benefit from market price increases. Due to decreased liquidity, the use of derivative instruments to manage this risk is generally limited to the forward twelve months. Net receipts from Duke for 2002 and 2001 were $17 million and $161 million, respectively. This keep-whole agreement and any associated derivative instruments are accounted for on a mark-to-market basis. The fair value of the short-term portion of the firm transportation keep-whole agreement is calculated with quoted natural gas basis prices. Basis is the difference in value between gas at various delivery points and the NYMEX gas futures contract price. Management believes that natural gas basis price quotes beyond the next twelve months are not reliable indicators of fair value due to decreasing liquidity. Accordingly, the fair value of the long-term portion is estimated based on historical natural gas basis prices, discounted at 10% per year. Management also periodically evaluates the supply and demand factors (such as expected drilling activity, anticipated pipeline construction projects, expected changes in demand at pipeline delivery points, etc.) that may impact the future market value of

8. Financial Instruments (Continued)

the firm transportation capacity to determine if the estimated fair value should be adjusted. The Company recognized other income of $35 million, $91 million and $175 million during 2002, 2001 and 2000, respectively, related to this agreement and associated derivative instruments. As of December 31, 2002 accounts payable included $5 million and other long-term liabilities included $68 million, related to the keep-whole agreement. As of December 31, 2001, other current assets included $25 million, accounts payable included $27 million and other long-term liabilities included $80 million related to the keep-whole agreement and associated derivative instruments.

Anticipated discounted and undiscounted liabilities for the firm transportation keep-whole agreement at December 31, 2002 are as follows:

millions	**Undiscounted**	**Discounted**
2003	$ 5	$ 5
2004	28	24
2005	20	16
2006	19	13
2007	14	9
Later years	9	6
Total	$95	$73

As of December 31, 2002, the Company had no natural gas volumes under derivative contracts related to the firm transportation keep-whole agreement. As of December 31, 2001, the Company had the following volumes of natural gas under derivative contracts related to the firm transportation keep-whole agreement:

Production Period	**Instrument Type**	**Volumes** (million MMBtu)	**Average Price** ($ per MMBtu)	**Net Fair Value Asset (Liability)** *millions*
2002	Swaps	4*	8.42	$25

* Represents 2% of the Company's total volumetric exposure under the keep-whole agreement for 2002.

Foreign Currency Risk Anadarko's Canadian subsidiaries use the Canadian dollar as their functional currency. The Company's other international subsidiaries use the U.S. dollar as their functional currency. To the extent that business transactions in these countries are not denominated in the respective country's functional currency, the Company is exposed to foreign currency exchange rate risk. In addition, in these subsidiaries, certain asset and liability balances are denominated in currencies other than the subsidiary's functional currency. These asset and liability balances are remeasured for the preparation of the subsidiary's financial statements using a combination of current and historical exchange rates, with any resulting remeasurement adjustments included in net income during the period.

At December 31, 2002 and 2001, the Company's Latin American subsidiaries had foreign deferred tax liabilities denominated in the local currency equivalent totaling $49 million and $78 million, respectively. During 2002, 2001 and 2000, the Company recognized tax benefits associated with remeasurement of these deferred tax liabilities of $35 million, $6 million and $1 million, respectively. In conjunction with the sale of certain properties in 2001, the Company indemnified a purchaser for the use of local tax losses denominated in local currency equivalent totaling $22 million. A loss of $1 million and a gain of $1 million, before taxes, were recognized related to the remeasurement of this liability and are included in other (income) expense during 2002 and 2001, respectively.

9. Preferred Stock

In May 1998, Anadarko issued $200 million of 5.46% Series B Cumulative Preferred Stock in the form of two million Depositary Shares, each Depositary Share representing 1/10th of a share of the 5.46% Series B Cumulative Preferred Stock. The preferred stock has no stated maturity and is not subject to a sinking fund or mandatory redemption. The shares are not convertible into other securities of the Company.

Anadarko has the option to redeem the shares at $100 per Depositary Share on or after May 15, 2008. Holders of the shares are entitled to receive, when, and as declared by the Board of Directors, cumulative cash dividends at an annual dividend rate of $5.46 per Depositary Share. In the event of a liquidation of the Company, the holders of the shares will be entitled to receive liquidating distributions in the amount of $100 per Depositary Share plus any accrued or unpaid dividends, before any distributions are made on the Company's common stock.

Anadarko repurchased $2 million and $97 million of preferred stock during 2002 and 2001, respectively. No gain or loss was recorded in 2002 related to the preferred stock repurchase activity. A gain of $13 million was recorded to paid-in capital during 2001. During 2002, 2001 and 2000, dividends of $54.60 per share (equivalent to $5.46 per Depositary Share) were paid to holders of preferred stock.

10. Common Stock and Stock Options

Following is a schedule of the changes in the Company's shares of common stock:

millions	**2002**	2001	2000
Shares of common stock issued			
Beginning of year	**254**	253	130
Issuance of common stock	**—**	—	114
Exercise of stock options	**1**	1	6
Issuance of restricted stock	**—**	—	2
Issuance of shares for unearned employee stock ownership plan	**—**	—	1
End of year	**255**	254	253
Shares of common stock held in treasury			
Beginning of year	**2**	—	—
Purchase of treasury stock	**1**	2	—
End of year	**3**	2	—
Shares of common stock held for unearned employee stock ownership plan			
Beginning of year	**1**	1	—
Issuance of stock	**—**	—	1
End of year	**1**	1	1
Shares of common stock held for Executives and Directors Benefits Trust			
Beginning of year	**2**	2	2
End of year	**2**	2	2
Shares of common stock outstanding at end of year	**249**	249	250

In the fourth quarter of 2002, dividends of 10 cents per share were paid to holders of common stock. For the first, second and third quarters of 2002 and the fourth quarter of 2001, dividends of 7.5 cents per share were paid to holders of common stock. For the first, second and third quarters of 2001 and for each quarter of 2000, dividends of 5 cents per share were paid to holders of common stock. The Company's credit agreements allow for a maximum capitalization ratio of 60% debt, exclusive of the effect of any non-cash writedowns. While there is

10. Common Stock and Stock Options (Continued)

no specific restriction on paying dividends, under the maximum debt capitalization ratio retained earnings were not restricted as to the payment of dividends at December 31, 2002 and 2001.

In July 2000, the stockholders of Anadarko approved an increase in the authorized number of Anadarko common shares from 300 million to 450 million. In July 2000, each share of common stock of Anadarko Holding issued and outstanding was converted into 0.455 shares of Anadarko common stock with approximately 114 million shares issued to the stockholders of Anadarko Holding.

The Anadarko Dividend Reinvestment and Stock Purchase Plan (DRIP) offers the opportunity to reinvest dividends and provides an alternative to traditional methods of buying, holding and selling Anadarko common stock. The DRIP provides the Company with a means of raising additional capital for general corporate purposes. The Company has a registration statement with the SEC that permits the issuance of up to 4.5 million additional shares of common stock under the DRIP.

Under the Anadarko Stockholders Rights Plan, Rights were attached automatically to each outstanding share of common stock in November 1998. Each Right, at the time it becomes exercisable and transferable apart from the common stock, entitles stockholders to purchase from the Company 1/1000th of a share of a new series of junior participating preferred stock at an exercise price of $175. The Right will be exercisable only if a person or group acquires 15% or more of common stock or announces a tender offer or exchange offer, the consummation of which would result in ownership by a person or group of 15% or more of the common stock. The Board of Directors may elect to exchange and redeem the Rights. The Rights expire in November 2008.

In 2001, the Board of Directors authorized the Company to purchase up to $1 billion in shares of Anadarko common stock. The share purchases may be made from time to time, depending on market conditions. Shares may be purchased either in the open market or through privately negotiated transactions. The repurchase program does not obligate Anadarko to acquire any specific number of shares and may be discontinued at any time. During 2001, the Company purchased 2.2 million shares of common stock for $116 million. In 2002, the Company purchased 1 million shares of common stock for $50 million. During 2000, the Company acquired treasury stock only as a result of stock option exercises, restricted stock transactions or buyback of shares, which were unsolicited from stockholders.

During 2002 and 2001 in conjunction with the stock purchase program, Anadarko sold put options to independent third parties. These put options entitled the holder to sell shares of Anadarko common stock to the Company on certain dates at specified prices. During 2001, Anadarko sold put options for the purchase of a total of 5 million shares of Anadarko common stock with a notional amount of $240 million. A put option for 1 million shares was exercised and put options for 2 million shares expired unexercised in 2001. Put options for the remaining 2 million shares expired unexercised in 2002. During 2001, premiums of $15 million were received related to these put options. In 2002, the Company entered into a put option for 1 million shares of Anadarko common stock with a notional amount of $46 million. The Company received premiums of $7 million during 2002. This put option expired unexercised in 2002. The premiums for put options were recorded as increases to paid-in capital. The put options permitted a net-share settlement at the Company's option and did not result in a liability on the consolidated balance sheet.

As of December 31, 2002 and 2001, the Company had 2 million shares of common stock in the Anadarko Petroleum Corporation Executives and Directors Benefits Trust (Trust) to secure present and future unfunded benefit obligations of the Company. These benefit obligations are provided for under pension plans and deferred compensation plans for certain employees and non-employee directors of the Company. The obligations included in Other Long-term Liabilities – Other are $46 million and $33 million as of December 31, 2002 and 2001, respectively. The shares issued to the Trust are not considered outstanding for quorum or voting calculations, but the Trust receives dividends. Under the treasury stock method, the shares are not included in the calculation of EPS. The fair market value of these shares is included in common stock and paid-in capital and as a reduction to stockholders' equity. See Note 18.

10. Common Stock and Stock Options (Continued)

Key employees may be granted options to purchase shares of Anadarko common stock and other stock related awards under the 1993 and the 1999 Stock Incentive Plans. Stock options are granted at the fair market value of Anadarko stock on the date of grant and have a maximum term of 11 years from the date of grant.

In addition, the Plans provide that shares of common stock may be granted as restricted stock. Generally, restricted stock is subject to forfeiture restrictions and cannot be sold, transferred or disposed of during the restriction period. The holders of the restricted stock have all the rights of a stockholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to such shares. During 2002, 2001 and 2000, the Company issued 0.2 million, 0.2 million and 1.2 million shares, respectively, of restricted stock with a weighted-average grant date fair value of $48.88, $61.26 and $50.21 per share, respectively. In 2002, 2001 and 2000, expense related to restricted stock grants was $15 million, $14 million and $8 million, respectively. In 2001 and 2000, 0.03 million and 0.5 million shares, respectively, of unrestricted common stock with a weighted-average grant date fair value of $65.71 and $48.53 per share, respectively, were issued related to the Anadarko Holding merger transaction. In 2001 and 2000, administrative and general expense of $2 million and $25 million, respectively, was recorded related to these shares. Also due to the Anadarko Holding merger transaction, 0.2 million shares of unrestricted common stock with a weighted-average grant date fair value of $48.53 per share were issued in 2000. A purchase price adjustment of $10 million was recorded related to these shares. See Note 4.

Non-employee directors may be granted non-qualified stock options or deferred stock under the 1998 Director Stock Plan. Stock options are granted at the fair market value of Anadarko stock on the date of grant and have a maximum term of ten years from the date of grant.

Unexercised stock options are included in the diluted EPS using the treasury stock method. Information regarding the Company's stock option plans is summarized below:

	2002		2001		2000	
option shares in millions	**Shares**	**Weighted-Average Exercise Price**	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Shares under option at beginning of year	**14.6**	**$42.49**	14.4	$41.28	8.9	$29.94
Granted	**1.4**	**$41.43**	1.0	$58.12	7.4	$48.80
Anadarko Holding options assumed at merger date	**—**	**$ —**	—	$ —	4.4	$38.93
Exercised	**(0.6)**	**$32.53**	(0.6)	$32.93	(6.3)	$32.32
Surrendered or expired	**(0.1)**	**$53.35**	(0.2)	$59.72	—	$40.26
Shares under option at end of year	**15.3**	**$42.68**	14.6	$42.49	14.4	$41.28
Options exercisable at December 31	**11.1**	**$40.93**	7.9	$36.26	6.0	$33.91
Shares available for future grant at end of year	**2.5**		3.6		4.8	
Weighted-average fair value of options granted during the year		**$18.86**		$22.71		$19.09

10. Common Stock and Stock Options (Continued)

The following table summarizes information about the Company's stock options outstanding at December 31, 2002:

	Options Outstanding			**Options Exercisable**	
Range of Exercise Prices	**Options Outstanding at Year End**	**Weighted-Average Remaining Contractual Life (Years)**	**Weighted-Average Exercise Price**	**Options Exercisable at Year End**	**Weighted-Average Exercise Price**
options in millions					
$ 0.00-$33.56	3.4	3.7	$27.34	3.3	$28.51
$33.60-$48.44	3.7	5.6	$40.23	2.3	$37.09
$48.53-$48.53	6.9	4.4	$48.53	4.8	$48.53
$48.94-$71.49	1.3	5.0	$58.60	0.7	$59.21
Total	15.3	4.6	$42.68	11.1	$40.93

The reconciliation between basic and diluted EPS is as follows:

	For the Year Ended December 31, 2002			For the Year Ended December 31, 2001			For the Year Ended December 31, 2000		
millions except per share amounts	**Income**	**Shares**	**Per Share Amount**	Loss	Shares	Per Share Amount	Income	Shares	Per Share Amount
Basic EPS									
Net income (loss) available to common stockholders before change in accounting principle	**$ 825**	**248**	**$ 3.32**	$ (183)	250	$ (0.73)	$ 813	184	$ 4.42
Effect of convertible debentures and ZYP-CODES	**9**	**10**		—	—		6	7	
Effect of dilutive stock options, performance-based stock awards and common stock put options	**—**	**2**		—	—		—	2	
Diluted EPS									
Net income (loss) available to common stockholders plus assumed conversion	**$ 834**	**260**	**$ 3.21**	$ (183)	250	$ (0.73)	$ 819	193	$ 4.25

For the years ended December 31, 2002, 2001 and 2000, options for 5.1 million, 1.2 million and 0.1 million average shares of common stock, respectively, were excluded from the diluted EPS calculation because the options' exercise price was greater than the average market price of common stock for the respective period. For the years ended December 31, 2002 and 2001, put options for 0.5 million and 1.8 million average shares, respectively, of common stock were excluded because the put options' exercise price was less than the average market price of common stock for the period. For the year ended December 31, 2001, there were 15.9 million potential common shares related to outstanding stock options, convertible debentures and ZYP-CODES that were excluded from the computation of diluted EPS because they had an anti-dilutive effect.

11. Statement of Cash Flows Supplemental Information

The amounts of cash paid for interest (net of amounts capitalized) and income taxes are as follows:

millions	**2002**	2001	2000
Interest	**$175**	$ 96	$90
Income taxes paid	**$ 67**	$169	$40

11. Statement of Cash Flows Supplemental Information (Continued)

The Anadarko Holding merger transaction was completed through the issuance of common stock, which was a non-cash transaction that was not reflected in the statement of cash flows. See Note 4. The $53 million of acquisition costs for 2000 reflected in Cash Flow from Investing Activities in the Consolidated Statement of Cash Flows represents capitalized merger costs in connection with the Anadarko Holding merger transaction of $147 million, less the cash acquired on the date of the Anadarko Holding merger transaction of $94 million.

12. Transactions with Related Parties and Major Customers

Anadarko has three Production Sharing Agreements (PSA) with Sonatrach, the national oil and gas enterprise of Algeria. Sonatrach has owned the Company's common stock since 1986 and at year-end 2002 was the registered owner of 4.9% of Anadarko's outstanding common stock. Each PSA gives Anadarko the right to explore, develop and produce liquid hydrocarbons in Algeria, subject to the sharing of production with Sonatrach.

Anadarko has two partners in the Block 404/208 PSA. Approximately $23 million, $10 million and $10 million was paid to Sonatrach in 2002, 2001 and 2000, respectively, for charges related to transportation of oil, oil purchases, well testing services, reservoir studies, laboratory services and equipment usage. During 2002, 2001 and 2000, zero, $7 million and $6 million, respectively, was received and $4 million and $7 million was included in accounts payable as of December 31, 2002 and 2001, respectively, from Sonatrach for joint interest billings of development costs in Algeria under the PSAs. During 2000, Anadarko and Sonatrach formed a non-profit company, Groupement Berkine, to carry out the majority of their joint operating activities under the PSA. Sonatrach and Anadarko fund the expenditures incurred by Groupement Berkine according to their participating interests under the PSA.

In 2001, Anadarko and its partners signed an amendment to the Block 404/208 PSA with Sonatrach, which allows exploration to resume on Blocks 404, 208 and 211 in areas outside of the exploitation license boundaries encompassing the previous discoveries. Under the terms of the new three-phase exploration program, Anadarko and its joint venture partners will spend a minimum of $55 million and began drilling exploration wells in 2002.

Anadarko signed two additional PSAs in 2001 and 2002 for Blocks 406b and 403c/e, respectively. The Company's interest in Block 406b is 100% and in Block 403c/e is 67%. Each agreement is for an initial three year exploration phase with work commitments including seismic acquisition and one exploration well.

Anadarko and partners have two Engineering, Procurement and Construction (EPC) contracts to build oil production facilities in Algeria with Brown & Root-Condor, a company jointly owned by Brown & Root and affiliates of Sonatrach. For the year ended December 31, 2000, approximately $4 million was paid to Brown & Root-Condor under the EPC contracts.

Political unrest continues in Algeria. Anadarko continually monitors the situation and has taken reasonable and prudent steps to ensure the safety of employees and the security of its facilities in the remote regions of the Sahara Desert. Anadarko is unable to predict with certainty any effect the current situation may have on activity planned for 2003 and beyond. However, the situation has had no material effect to date on the Company's operations in Algeria, where the Company has had activities since 1989. The Company's activities in Algeria also are subject to the general risks associated with all foreign operations.

Anadarko recognized revenues of $12 million in 2001 for cumulative preferred dividends declared by OCI Wyoming Co., an equity affiliate. Anadarko owns a 20% common stock interest in OCI Wyoming Co. along with 100% of the cumulative preferred stock. The amount recorded to income in 2001 was for dividends in arrears for the period 1999 through 2001.

The Company's natural gas is sold to interstate and intrastate gas pipelines, direct end-users, industrial users, local distribution companies and gas marketers. Crude oil and condensate are sold to marketers, gatherers and refiners. NGLs are sold to direct end-users, refiners and marketers. These purchasers are located in the United States, Canada, England, Germany, Italy, Mexico, Switzerland and Turkey. The majority of the Company's receivables are paid within two months following the month of purchase.

12. Transactions with Related Parties and Major Customers (Continued)

The Company generally performs a credit analysis of customers prior to making any sales to new customers or increasing credit for existing customers. Based upon this credit analysis, the Company may require a standby letter of credit or a financial guarantee. As of December 31, 2002 and 2001, accounts receivable are shown net of allowance for doubtful accounts of $16 million and $44 million, respectively.

In 2002, 2001 and 2000, sales to Duke Energy and affiliates were $843 million, $1.4 billion and $1.0 billion, respectively, which accounted for 22%, 31% and 35% of the Company's total 2002, 2001 and 2000 revenues, respectively.

13. Segment and Geographic Information

Anadarko's primary business segments are vertically integrated business units that are principally within the oil and gas industry. These segments are managed separately because of their unique technology, marketing and distribution requirements. The Company's three segments are upstream oil and gas activities, marketing and trading activities and minerals activities. The oil and gas exploration and production segment finds and produces natural gas, crude oil, condensate and NGLs. The marketing and trading segment is responsible for gathering, transporting and selling most of Anadarko's natural gas production as well as volumes of gas, oil and NGLs purchased from third parties. The minerals segment finds and produces minerals in several coal, trona (natural soda ash) and industrial mineral mines. The segment shown as Intercompany Eliminations and All Other includes other smaller operating units, corporate activities, financing activities and intercompany eliminations.

The Company's accounting policies for segments are the same as those described in the summary of accounting policies. Management evaluates segment performance based on profit or loss from operations before income taxes and various other factors. Transfers between segments are accounted for at market value.

The following table illustrates information related to Anadarko's business segments:

millions	Oil and Gas Exploration and Production	Marketing and Trading	Minerals	Intercompany Eliminations and All Other	Total
2002					
Revenues	$ 2,443	$ 126	$ 41	$ 1,250	$ 3,860
Intersegment revenues	1,236	9	—	(1,245)	—
Total revenues	3,679	135	41	5	3,860
Depreciation, depletion and amortization	1,056	19	3	43	1,121
Impairments related to oil and gas properties	39	—	—	—	39
Other costs and expenses	907	116	2	250	1,275
Total costs and expenses	2,002	135	5	293	2,435
Other (income) expense	—	(35)	—	253	218
Income (loss) before income taxes	$ 1,677	$ 35	$ 36	$ (541)	$ 1,207
Net properties and equipment	$13,204	$ 237	$1,202	$ 455	$15,098
Capital expenditures	$ 2,310	$ 13	$ —	$ 65	$ 2,388
Goodwill	$ 1,434	$ —	$ —	$ —	$ 1,434

13. Segment and Geographic Information (Continued)

millions	Oil and Gas Exploration and Production	Marketing and Trading	Minerals	Intercompany Eliminations and All Other	Total
2001					
Revenues	$ 3,172	$ 125	$ 57	$ 1,364	$ 4,718
Intersegment revenues	1,371	17	—	(1,388)	—
Total revenues	4,543	142	57	(24)	4,718
Depreciation, depletion and amortization	1,110	12	4	28	1,154
Impairments related to oil and gas properties	2,546	—	—	—	2,546
Other costs and expenses	950	115	4	312	1,381
Total costs and expenses	4,606	127	8	340	5,081
Other (income) expense	—	(91)	—	118	27
Income (loss) before income taxes	$ (63)	$ 106	$ 49	$ (482)	$ (390)
Net properties and equipment	$11,765	$ 253	$1,206	$ 413	$13,637
Capital expenditures	$ 3,072	$ 66	$ —	$ 178	$ 3,316
Goodwill	$ 1,430	$ —	$ —	$ —	$ 1,430
2000					
Revenues	$ 1,938	$ 48	$ 52	$ 873	$ 2,911
Intersegment revenues	866	66	—	(932)	—
Total revenues	2,804	114	52	(59)	2,911
Depreciation, depletion and amortization	570	8	2	13	593
Impairments related to oil and gas properties	50	—	—	—	50
Other costs and expenses	575	170	2	169	916
Total costs and expenses	1,195	178	4	182	1,559
Other (income) expense	—	(174)	—	100	(74)
Income (loss) before income taxes	$ 1,609	$ 110	$ 48	$ (341)	$ 1,426
Net properties and equipment	$11,330	$ 166	$1,211	$ 304	$13,011
Capital expenditures	$ 1,630	$ 41	$ —	$ 37	$ 1,708
Goodwill	$ 1,317	$ —	$ —	$ —	$ 1,317

13. Segment and Geographic Information (Continued)

The following table shows Anadarko's revenues (based on the origin of the sales) and net properties and equipment by geographic area:

millions	**2002**	2001	2000
Revenues			
United States	**$2,476**	$3,537	$2,175
Canada	**653**	794	332
Algeria	**572**	195	271
Other International	**159**	192	133
Total	**$3,860**	$4,718	$2,911

millions	**2002**	2001
Net Properties and Equipment		
United States	**$11,258**	$10,072
Canada	**2,096**	2,010
Algeria	**898**	807
Other International	**846**	748
Total	**$15,098**	$13,637

14. Other Taxes

Significant taxes other than income taxes are as follows:

millions	**2002**	2001	2000
Production and severance	**$ 99**	$139	$ 88
Ad valorem	**91**	85	28
Payroll and other	**24**	23	12
Total	**$214**	$247	$128

15. Other (Income) Expense

Other (income) expense consists of the following:

millions	**2002**	2001	2000
Firm transportation keep-whole contract valuation (See Note 8)	**$(35)**	$ (91)	$ (175)
Unrealized (gain) loss on derivative instruments	**33**	(18)	—
Gas sales contracts — accretion of discount	**11**	14	—
Foreign currency exchange*	**1**	29	7
Other	**5**	1	1
Total	**$ 15**	$ (65)	$ (167)

* The years ended December 31, 2002, 2001 and 2000, exclude $35 million, $6 million and $1 million, respectively, in transaction gains related primarily to remeasurement of the Venezuelan deferred tax liability, which is included in income tax expense.

16. Income Taxes

Income tax expense (benefit), including deferred amounts, is summarized as follows:

millions	**2002**	2001	2000
Current			
Federal	**$ (8)**	$ 32	$ 8
State	**9**	5	3
Foreign	**178**	50	67
Total	**179**	87	78
Deferred			
Federal	**194**	(38)	405
State	**10**	(5)	24
Foreign	**(7)**	(258)	95
Total	**197**	(301)	524
Total	**$376**	$ (214)	$602

Total income taxes were different than the amounts computed by applying the statutory income tax rate to income (loss) before income taxes. The sources of these differences are as follows:

millions	**2002**	2001	2000
Income (Loss) Before Income Taxes			
Domestic	**$ 706**	$ 67	$1,085
Foreign	**501**	(457)	341
Total	**$1,207**	$ (390)	$1,426
Statutory tax rate	**35%**	35%	35%
Tax computed at statutory rate	**$ 423**	$ (137)	$ 499
Adjustments resulting from:			
State income taxes (net of federal income tax benefit)	**12**	—	17
Oil and gas credits	**(15)**	(22)	(13)
Taxes related to foreign operations (net of federal income tax benefit)	**(42)**	(51)	134
Reversal of goodwill amortization	**—**	22	11
Effect of change in Canadian income tax rates	**(5)**	(31)	—
Other — net	**3**	5	(46)
Total income tax expense (benefit)	**$ 376**	$ (214)	$ 602
Effective tax rate	**31%**	55%	42%

The tax benefit of compensation expense for tax purposes in excess of amounts recognized for financial accounting purposes has been credited directly to stockholders' equity. For 2002, 2001 and 2000, the tax benefit amounted to $8 million, $6 million and $67 million, respectively.

A net tax benefit of $42 million resulting from the Company's restructuring of certain foreign operations in 2000 was recorded to a deferred liability account. An additional net tax benefit of $49 million was recorded to the account during 2001. In addition, a net tax benefit previously recorded to the account in the amount of $152 million was reversed to goodwill in 2001 as a result of the sale of a wholly-owned subsidiary resulting in a net deferred asset balance. A net tax liability of $24 million resulting from the Company's restructuring of certain foreign operations in 2002 was recorded as an offset to the account. The resulting deferred asset is reflected in the Company's other long-term assets.

16. Income Taxes (Continued)

In 2001, tax expense in the amount of $10 million was recorded directly to goodwill relating to the sale of a wholly-owned subsidiary, which was acquired in a corporate acquisition.

The tax effects of temporary differences that give rise to significant portions of the deferred tax liabilities (assets) at December 31, 2002 and 2001 are as follows:

millions	**2002**	2001
Oil and gas exploration and development costs	**$2,938**	$2,797
Mineral operations	**419**	422
Other	**795**	506
Gross noncurrent deferred tax liabilities	**4,152**	3,725
Net operating loss carryforward	**(28)**	—
Alternative minimum tax credit carryforward	**(146)**	(136)
Other	**(378)**	(169)
Gross noncurrent deferred tax assets	**(552)**	(305)
Less: valuation allowance	**33**	31
Net noncurrent deferred tax assets	**(519)**	(274)
Net noncurrent deferred tax liabilities	**$3,633**	$3,451

The $2 million net increase in the valuation allowance during 2002 is primarily attributable to a change in judgment about the expected realization of an existing foreign deferred tax asset.

Tax carryforwards at December 31, 2002, which are available for future utilization on income tax returns, are as follows:

millions	**Domestic**	**Foreign**	**Expiration**
Alternative minimum tax credit	$146	$ —	Unlimited
General business tax credit	$ 42	$ —	2006-2021
Net operating loss	$ —	$ 62	2003-2004
Capital loss - domestic	$ 23	$ —	2007
Capital loss - foreign	$ —	$ 23	Unlimited
Foreign tax credit	$ 4	$ —	2005

17. Commitments

The Company has various commitments under non-cancelable operating lease agreements for buildings, facilities, aircraft and equipment, the majority of which expire at various dates through 2016. The Company also maintains a capital lease for certain furniture and office walls, which were sold but the liability was retained. The majority of the operating leases are expected to be renewed or replaced as they expire. At December 31, 2002, future minimum lease payments and receipts due under operating and capital leases are as follows:

millions	Capital Leases	Operating Leases	Operating Sublease Income
2003	$ 3	$ 72	$(29)
2004	6	67	(6)
2005	1	55	(5)
2006	—	52	(5)
2007	—	53	(5)
Later years	—	208	(21)
Total future minimum lease payments	10	$507	$(71)
Less: amounts representing interest	(1)		
Present value of minimum capital lease obligations	9		
Less: short-term portion of capital lease obligations	(2)		
Long-term portion of capital lease obligations	$ 7		

Total rental expense, net of sublease income, amounted to $42 million, $43 million and $48 million in 2002, 2001 and 2000, respectively.

Synthetic Leases Anadarko has two lease arrangements for its corporate office buildings in The Woodlands, Texas. The development and acquisition of the properties were financed by special purpose entities (SPEs) sponsored by a financial institution. The total amount funded under these leases was $213 million. The SPEs are not consolidated in the Company's financial statements, and based on the terms of the agreements, the Company has accounted for these arrangements as operating leases in accordance with SFAS No. 13, ''Accounting for Leases,'' and the table above includes the lease payment obligations.

The initial lease term for each lease is five years. Monthly lease payments are based on the London interbank borrowing rate applied against the lease balance. Future minimum lease payments are included in the above table. The leases contain various covenants including covenants regarding the Company's financial condition. Default under the leases, including violation of these covenants, could require the Company to purchase the facilities for a specified amount, which approximates the lessor's original cost ($213 million). As of December 31, 2002, the Company was in compliance with these covenants.

At the end of the lease term, the Company has an option to either purchase the facilities for the purchase option amount of the lease balance plus any outstanding lease payments or to assist the SPEs in the sale of the properties. The Company has provided a residual value guarantee for any deficiency if the properties are sold for less than the sale option amount ($178 million at December 31, 2002). In addition, the Company is entitled to any proceeds from a sale of the properties in excess of the purchase option amount.

If for either of these leases, the Company determines that it is probable that the expected fair value of the property at the end of the lease term will be less than the purchase option amount, the Company will accrue the expected loss on a straight line basis over the remaining lease term. Currently, Management does not believe it is probable that the fair market value of either of these properties will be less than the purchase option amount at the end of the lease term. As such, no liability has been recognized for these guarantees as of December 31, 2002.

17. Commitments (Continued)

In addition, the table above includes the Company's lease payment obligations of $11 million related to aircraft operating leases financed by synthetic leases. One of these aircraft leases is a synthetic lease with a residual value guarantee for any deficiency if the aircraft is sold for less than the sale option amount (approximately $11 million). In addition, the Company is entitled to any proceeds from a sale of the aircraft in excess of the sale option amount. No liability has been recorded related to this guarantee.

As discussed in Note l, the Company is evaluating the impact of the 2003 adoption of FIN No. 45 and FIN No. 46 on accounting for and the possible restructuring of the synthetic leases and related guarantees.

Production Platform In April 2002, the Company signed an agreement under which a floating production platform for its Marco Polo discovery in Green Canyon Block 608 of the Gulf of Mexico will be installed. The other party to the agreement will construct and own the platform and production facilities that upon completion, expected in late 2003, will be operated by Anadarko. The agreement provides that Anadarko dedicate its production from Green Canyon Block 608 and 11 other Green Canyon blocks to the production facilities. The agreement requires a monthly demand charge of slightly over $2 million for five years beginning at the time of project completion and a processing fee based upon production throughput. Since the Company's obligation to make these lease payments begins at the time of project completion, the table of future minimum lease payments above does not include any amounts related to this agreement. The agreement does not contain any purchase options, purchase obligations or value guarantees.

18. Pension Plans, Other Postretirement Benefits and Employee Savings Plans

Pension Plans and Other Postretirement Benefits The Company has defined benefit pension plans and supplemental plans which are non-contributory pension plans. In January 2003, the Company made a $52 million contribution to one of the defined benefit pension plans. The Company also provides certain health care and life insurance benefits for retired employees. Health care benefits are funded by contributions from the Company and the retiree, with the retiree contributions adjusted to match the provisions of the Company's health care plans. The Company's retiree life insurance plan is non-contributory.

18. Pension Plans, Other Postretirement Benefits and Employee Savings Plans (Continued)

The following table sets forth the Company's pension and other postretirement benefits changes in benefit obligation, fair value of plan assets, funded status and amounts recognized in the financial statements as of December 31, 2002 and 2001.

	Pension Benefits		Other Benefits	
millions	**2002**	2001	**2002**	2001
Change in benefit obligation				
Benefit obligation at beginning of year	**$ 417**	$377	**$ 123**	$ 75
Service cost	**14**	11	**5**	3
Interest cost	**29**	27	**8**	5
Plan amendments	**—**	10	**(7)**	20
Actuarial loss	**61**	18	**8**	25
Foreign currency exchange rate change	**—**	(2)	**—**	—
Benefit payments and settlements	**(32)**	(24)	**(6)**	(5)
Benefit obligation at end of year	**$ 489**	$417	**$ 131**	$ 123
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 338**	$396	**$ —**	$ —
Actual return on plan assets	**(26)**	(32)	**—**	—
Employer contributions	**6**	1	**6**	5
Foreign currency exchange rate change	**—**	(3)	**—**	—
Benefit payments	**(32)**	(24)	**(6)**	(5)
Fair value of plan assets at end of year	**$ 286**	$338	**$ —**	$ —
Funded status of the plan	**$(203)**	$ (79)	**$(131)**	$(123)
Unrecognized actuarial loss	**195**	80	**31**	23
Unrecognized prior service cost	**8**	8	**8**	16
Unrecognized initial asset	**(1)**	(2)	**—**	—
Total recognized	**$ (1)**	$ 7	**$ (92)**	$ (84)
Total recognized amounts in the balance sheet consist of:				
Prepaid benefit cost	**$ 24**	$ 23	**$ —**	$ —
Accrued benefit liability	**(155)**	(51)	**(92)**	(84)
Intangible asset	**11**	31	**—**	—
Other comprehensive expense	**119**	4	**—**	—
Total recognized	**$ (1)**	$ 7	**$ (92)**	$ (84)

Following are the weighted-average assumptions used by the Company in determining the accumulated pension and postretirement benefit obligations as of December 31, 2002 and 2001:

	Pension Benefits		Other Benefits	
percent	**2002**	2001	**2002**	2001
Discount rate	**6.75%**	7.25%	**6.75%**	7.25%
Long-term rate of return on plan assets	**8.0%**	9.0%	**n/a**	n/a
Rates of increase in compensation levels	**5.0%**	5.0%	**5.0%**	5.0%

18. Pension Plans, Other Postretirement Benefits and Employee Savings Plans (Continued)

For measurement purposes, a 9% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2002. The rate was assumed to decrease gradually to 5% in 2006 and later years.

	Pension Benefits			Other Benefits		
millions	**2002**	2001	2000	**2002**	2001	2000
Components of net periodic benefit cost						
Service cost	**$ 14**	$ 11	$ 8	**$ 5**	$ 3	$ 2
Interest cost	**29**	27	15	**8**	6	4
Expected return on plan assets	**(31)**	(28)	(13)	**—**	—	—
Amortization values and deferrals	**4**	1	—	**1**	(1)	(1)
Net periodic benefit cost	**$ 16**	$ 11	$ 10	**$14**	$ 8	$ 5

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $467 million, $404 million and $251 million, respectively, as of December 31, 2002, and $395 million, $346 million and $297 million, respectively, as of December 31, 2001. The Company's benefit obligation under the unfunded pension plans are secured by the Anadarko Petroleum Corporation Executives and Directors Benefits Trust. See Note 10.

The assumed health care cost trend rate has a significant effect on the amounts reported for the health care plan. A 1% change in the assumed health care cost trend rate would have the following effects:

millions	1% Increase	1% Decrease
Effect on total of service and interest cost components	$ 2	$ (2)
Effect on postretirement benefit obligation	$15	$(14)

Employee Savings Plan The Company has an employee savings plan (ESP), which is a defined contribution plan. The Company matches a portion of employees' contributions with shares of the Company's common stock. Participation in the ESP is voluntary and all regular employees of the Company are eligible to participate. The Company charged to expense plan contributions of $12 million, $11 million and $7 million during 2002, 2001 and 2000, respectively. The 2002 and 2001 contributions were funded through the Employee Stock Ownership Plan (ESOP).

Employee Stock Ownership Plan In July 2000, Anadarko adopted the Anadarko Holding ESOP and the shares in the ESOP were converted to shares of Anadarko common stock. In July 2000, the ESOP consisted of 1.2 million shares or $74 million of common stock (the ESOP shares) to be used to fund the Company's matching obligation under the Anadarko Holding Thrift Plan. All domestic regular employees of Anadarko Holding were eligible to participate in the ESOP. Effective December 31, 2000, the ESOP was merged into the Anadarko Holding Thrift Plan, which was merged into the Anadarko ESP. Beginning January 2001, the Company began using unallocated ESOP shares for Company matching under the Anadarko ESP.

The ESOP shares, which are held in trust, were originally purchased with the proceeds from a 30-year loan from Anadarko Holding in 1997. These shares were pledged as collateral for the loan. As loan payments are made, shares are released from collateral, based on the proportion of debt service paid. Scheduled principal and interest requirements are funded with dividends paid on the ESOP shares and with cash contributions from the Company. Principal or interest prepayments may be made to ensure that the Company's minimum matching obligation is met.

Shares held by the ESOP are included in the computation of earnings per share as ESOP shares are released from collateral. Releases of ESOP shares will be allocated to participants' accounts and will be charged to compensation expense at the fair market value of the shares on the date of the employer match.

18. Pension Plans, Other Postretirement Benefits and Employee Savings Plans (Continued)

As of December 31, 2002 and 2001, the unallocated shares in the ESOP were 0.7 million and 0.9 million, respectively, and the fair value of unallocated ESOP shares at December 31, 2002 and 2001 was $32 million and $52 million, respectively. In 2000, compensation cost related to the allocation of ESOP shares to participants' accounts, other than expense under the ESP plan, was $2 million. In 2002 and 2001, no compensation cost related to the allocation of ESOP shares, other than expense under the ESP, was recorded.

19. Contingencies

General The Company is a defendant in a number of lawsuits and is involved in governmental proceedings arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. The Company has also been named as a defendant in various personal injury claims, including numerous claims by employees of third-party contractors alleging exposure to asbestos and benzene while working at a refinery in Corpus Christi, Texas, which Anadarko Holding sold in segments in 1987 and 1989. While the ultimate outcome and impact on the Company cannot be predicted with certainty, Management believes that the resolution of these proceedings will not have a material adverse effect on the consolidated financial position of the Company, although results of operations and cash flow could be significantly impacted in the reporting periods in which such matters are resolved. Discussed below are several specific proceedings.

Royalty Litigation During September 2000, the Company was named as a defendant in a case styled *U.S. of America ex rel. Harold E. Wright v. AGIP Company, et al.* (the ''Gas Qui Tam case'') filed in the U.S. District Court for the Eastern District of Texas, Lufkin Division. This lawsuit generally alleges that the Company and 118 other defendants improperly measured and otherwise undervalued natural gas in connection with a payment of royalties on production from federal and Indian lands. The case has been transferred to the U.S. District Court, Multi-District Litigation Docket pending in Wyoming. Based on the Company's present understanding of the various governmental and False Claims Act proceedings described above, the Company believes that it has substantial defenses to these claims and intends to vigorously assert such defenses. However, if the Company is found to have violated the Civil False Claims Act, the Company could be subject to a variety of sanctions, including treble damages and substantial monetary fines. Motions to dismiss on the grounds that plaintiffs did not provide new information for the government to file suit upon were filed in January 2003, with a hearing date expected in May 2003.

A group of royalty owners purporting to represent Anadarko Holding's gas royalty owners in Texas (*Neinast, et al.*) was granted class action certification in December 1999, by the 21st Judicial District Court of Washington County, Texas, in connection with a gas royalty underpayment case against the Company. This certification did not constitute a review by the Court of the merits of the claims being asserted. The royalty owners' pleadings did not specify the damages being claimed, although most recently a demand for damages in the amount of $100 million was asserted. The Company appealed the class certification order. A favorable decision from the Houston Court of Appeals decertified the class. The royalty owners did not appeal this matter to the Texas Supreme Court and the decision from the Houston Court of Appeals became final in the second quarter of 2002. The royalty owners recently filed a new petition alleging that the class may properly be brought so long as ''sub-class'' groups are broken out. The Company is vigorously contesting this new petition.

A class action lawsuit entitled *Gilbert H. Coulter, et al. v. Anadarko Petroleum Corporation* has been certified in the 26th Judicial District Court, Stevens County, Kansas. In this action, the royalty owners contend that royalty was underpaid as a result of the deduction for certain post-production costs in the calculation of royalty. The Company believes that its method of calculating royalty was proper and that its gas was marketable in the condition produced, and thus plaintiffs' claims are without merit. This case was certified as a class action in August 2000 and was tried in February 2002. It is uncertain at this time when the trial court will render its ruling.

Superfund — Operating Industries, Inc. (Federal) — The former municipal industrial landfill, located in Monterey Park, California, was operational between 1948 and 1984. Anadarko Holding was noticed as a

19. Contingencies (Continued)

Potentially Responsible Party in June 1986 for its Wilmington Production Field's and Wilmington Refinery's contributions. The Company participated in a settlement with the Environmental Protection Agency. The Company's share of the settlement was about $5 million.

CITGO Litigation CITGO Petroleum Corporation's (CITGO) claims arise out of an Asset Purchase and Contribution Agreement in 1987 whereby Anadarko Holding's predecessor sold a refinery located in Corpus Christi, Texas, to CITGO's predecessor. After the sale of the refinery, numerous individuals living near the refinery sued CITGO (the Neighborhood Litigation) thereby implicating the Asset Purchase and Contribution Agreement indemnity provision. CITGO and Anadarko Holding eventually entered into a settlement agreement to allocate, on an interim basis, each party's liability for defense and liability cost in that and related litigation. That agreement provides that once the Neighborhood Litigation and certain related claims are resolved, then the parties will determine their final indemnity obligations to each other through binding arbitration. At the present time, Anadarko Holding and CITGO have agreed to defer arbitrating the allocation of responsibility for this liability in order to focus their efforts on a global settlement. Arbitration will resume upon request of either CITGO or Anadarko Holding. In conjunction with this matter, Anadarko Holding sued Continental Insurance for denial of coverage for claims related to this dispute. Anadarko Holding and Continental Insurance settled the insurance coverage litigation which resulted in Continental Insurance paying a portion of Anadarko Holding's claims. Negotiations and discussions with CITGO continue. Anadarko Holding has offered to settle all outstanding issues for approximately $4 million and a liability for this amount has been accrued.

Kansas Ad Valorem Tax

General The Natural Gas Policy Act of 1978 allowed a ''severance, production or similar'' tax to be included as an add-on, over and above the maximum lawful price charged for natural gas. Based on the Federal Energy Regulatory Commission (FERC) ruling that the Kansas ad valorem tax was such a tax, the Company collected the Kansas ad valorem tax.

Background of PanEnergy Litigation FERC's ruling regarding the ability of producers to collect the Kansas ad valorem tax was appealed to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The Court held in June 1988 that FERC failed to provide a reasoned basis for its findings and remanded the case to FERC.

Ultimately, the D.C. Circuit issued a decision on August 2, 1996 ruling that producers must refund all Kansas ad valorem taxes collected relating to production since October 1983. The Company filed a petition for writ of certiorari with the Supreme Court. That petition was denied on May 12, 1997.

PanEnergy Litigation On May 13, 1997, the Company filed a lawsuit in the Federal District Court for the Southern District of Texas against PanEnergy seeking declaration that pursuant to prior agreements Anadarko is not required to issue refunds to PanEnergy for the principal amount of $14 million (before taxes) and, if the petition for adjustment is denied in its entirety by FERC with respect to PanEnergy refunds, interest in an amount of $38 million (before taxes). The Company also sought from PanEnergy the return of the $1 million (before taxes) charged against income in 1993 and 1994. In October 2000, the U.S. Magistrate issued recommendations concerning motions for summary judgment previously filed by both parties. In essence, the Magistrate's recommendation finds that the Company should be responsible for refunds attributable to the time period following August 1, 1985 while Duke Energy (as the successor company to Anadarko Production Company) should be responsible for refunds attributable to the time period before August 1, 1985.

The Company has reached a settlement agreement with PanEnergy that requires the Company to pay $15 million for settlement in full of all matters relating to the refunds of Kansas ad valorem tax reimbursements collected by the Company as first seller from August 1, 1985 through 1988. The settlement agreement was approved by FERC and paid by Anadarko during 2001. The settlement agreement does not have any impact on

19. Contingencies (Continued)

the outstanding dispute between the Company and PanEnergy in connection with the refunds that relate to the Cimmaron River System. Anadarko's net income for 2001 included a $15 million charge (before taxes) related to the settlement agreement. Discussions with the Kansas Corporation Commission and PanEnergy to reach a settlement of the Cimmaron River System dispute are ongoing. At this time, it is estimated that a resolution may be reached in the first quarter of 2003, that may result in payment of about $6 million by the Company. A provision was charged against income in 2001.

Other Litigation The Company has a reserve of about $2 million for Kansas ad valorem tax refunds. This amount reflects all principal and interest which may be due at the conclusion of all regulatory proceedings and litigation to parties other than PanEnergy.

Lease Agreement The Company, through one of its affiliates, is a party to a lease agreement (base lease) for the leveraged lease financing of the Corpus Christi West Plant Refinery (West Plant) with an initial term expiring December 31, 2003, and successive renewal periods lasting through January 31, 2011. At the conclusion of the initial term of the base lease, any renewal period or January 31, 2011, the Company has the right to purchase the West Plant at the fair market sales value. In connection with the sale by Anadarko Holding of its refining business in 1987 and 1989, the West Plant was subleased to CITGO with sublease payments during the initial term equal to the Company's base lease payments and during any renewal period equal to the lesser of the base lease rental, which will be tied to the annual fair market rental value or a specified maximum amount. Additionally, CITGO has the option under the sublease to purchase the West Plant from the Company at the conclusion of the initial term or any renewal term at the fair market sales value, or on January 31, 2011 at a nominal price. If the fair market rental value of the base lease during any renewal term exceeds CITGO's maximum obligation under the sublease, or if CITGO purchases the West Plant on January 31, 2011 and the fair market sales value of the West Plant is greater than the purchase amount specified in the sublease, the Company will be obligated to pay the excess amounts. The Company is unable at this time to determine the fair market rental value or the fair market sales value of the West Plant, but will at least annually evaluate the potential effect of the obligation. Thus, no liability has been recognized as of December 31, 2002.

Guarantees Anadarko is guarantor for certain obligations of its wholly-owned and consolidated subsidiaries, which are included in the consolidated financial statements and notes. In addition, the Company is guarantor for specific financial obligations of two trona mining affiliates. The investments in these entities, which are not consolidated subsidiaries, are accounted for using the equity method. The Company has guaranteed a portion of amounts due under a revolving credit agreement and various letters of credit used to secure Industrial Revenue Bonds and environmental surety bonds. The Company's guarantee under the revolving credit agreement expires in 2005 coinciding with the maturity of that agreement. Expiration dates of the Company's guarantees under the letters of credit securing the Industrial Revenue Bonds and environmental surety bonds range from 2003 to 2004; however, it is the intent of the Company to renew these letters of credit and the related guarantees until the maturity dates of the obligations which range from 2003 to 2018. The amounts the Company would be obligated to pay should the affiliates default on these obligations would be up to $13 million for the revolving credit agreement, $8 million for environmental surety bonds and $15 million for the Industrial Revenue Bonds. No liability has been recognized for these guarantees as of December 31, 2002.

19. Contingencies (Continued)

In connection with its various acquisitions, the Company routinely indemnifies the former officers and directors of acquired companies in respect to acts or omissions occurring prior to the effective date of the acquisition. The Company also agrees to maintain directors' and officers' liability insurance on these individuals with respect to acts or omissions occurring prior to the acquisition, generally for a period of six years. No liability has been recognized for these indemnifications.

The Company also provides certain indemnifications in relation to dispositions of assets. These indemnifications typically relate to disputes, litigation or tax matters existing at the date of disposition. In connection with a sale of properties in 2001, the Company indemnified the purchaser for the use of certain currency remeasurement losses utilized by the Company in previously filed tax returns, which are currently being evaluated by the taxing authorities. The Company believes it is probable that these losses will be disallowed and will have to be settled with the purchaser in cash. The Company has a $22 million liability recorded for the contingency.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Oil and Gas Exploration and Production Activities

The following is historical revenue and cost information relating to the Company's oil and gas activities.

Costs Excluded

Excluded from amounts subject to amortization as of December 31, 2002 and 2001 are $3.1 billion and $3.6 billion, respectively, of costs associated with unevaluated properties and major development projects. The majority of the evaluation activities are expected to be completed within five to ten years.

Costs Excluded by Year Incurred

	Year Costs Incurred				Excluded Costs at
millions	Prior Years	2000	2001	2002	Dec. 31, 2002
Property acquisition	$43	$1,085	$ 99	$193	$1,420
Exploration	25	646	423	284	1,378
Capitalized interest	5	50	109	123	287
Total	$73	$1,781	$631	$600	$3,085

Costs Excluded by Country

millions	U.S.	Canada	Algeria	Other International	Total
Property acquisition	$1,355	$ 65	$—	$ —	$1,420
Exploration	787	410	11	170	1,378
Capitalized interest	238	34	—	15	287
Total	$2,380	$509	$11	$185	$3,085

Changes in Costs Excluded by Country

millions	U.S.	Canada	Algeria	Other International	Total
December 31, 2000	$ 2,308	$ 412	$ 15	$ 163	$ 2,898
Additional costs incurred in 2001	939	528	1	96	1,564
Costs transferred to DD&A pool in 2001	(487)	(348)	(16)	(38)	(889)
December 31, 2001	2,760	592	—	221	3,573
Additional costs incurred in 2002	899	71	11	66	1,047
Costs transferred to DD&A pool in 2002	(1,279)	(154)	—	(102)	(1,535)
December 31, 2002	$ 2,380	$ 509	$ 11	$ 185	$ 3,085

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Capitalized Costs Related to Oil and Gas Producing Activities

millions	**2002**	2001
United States		
Capitalized		
Unproved properties	**$ 2,380**	$ 2,760
Proved properties	**12,639**	10,464
	15,019	13,224
Accumulated depreciation, depletion and amortization	**5,621**	5,007
Net capitalized costs	**9,398**	8,217
Canada		
Capitalized		
Unproved properties	**509**	592
Proved properties	**2,870**	2,493
	3,379	3,085
Accumulated depreciation, depletion and amortization	**1,309**	1,086
Net capitalized costs	**2,070**	1,999
Algeria		
Capitalized		
Unproved properties	**11**	—
Proved properties	**1,052**	907
	1,063	907
Accumulated depreciation, depletion and amortization	**173**	106
Net capitalized costs	**890**	801
Other International		
Capitalized		
Unproved properties	**185**	221
Proved properties	**821**	610
	1,006	831
Accumulated depreciation, depletion and amortization	**160**	83
Net capitalized costs	**846**	748
Total		
Capitalized		
Unproved properties	**3,085**	3,573
Proved properties	**17,382**	14,474
	20,467	18,047
Accumulated depreciation, depletion and amortization	**7,263**	6,282
Net capitalized costs	**$13,204**	$11,765

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Costs Incurred in Oil and Gas Producing Activities

millions	**2002**	2001	2000
United States — Capitalized			
Property acquisition			
Exploration	**$ 341**	$ 156	$1,897
Development	**248**	31	2,984
Exploration	**654**	840	353
Development	**715**	1,196	777
	1,958	2,223	6,011
Canada — Capitalized			
Property acquisition			
Exploration	**25**	309	437
Development	**3**	835	1,075
Exploration	**138**	223	16
Development	**237**	233	89
	403	1,600	1,617
Algeria — Capitalized			
Exploration	**15**	2	7
Development	**140**	179	155
	155	181	162
Other International — Capitalized			
Property acquisition			
Exploration	**11**	30	122
Development	**26**	67	532
Exploration	**54**	65	39
Development	**108**	136	33
	199	298	726
Total — Capitalized			
Property acquisition			
Exploration	**377**	495	2,456
Development	**277**	933	4,591
Exploration	**861**	1,130	415
Development	**1,200**	1,744	1,054
	$2,715	$4,302	$8,516

Development costs for 2002 include costs related to December 31, 2001 proved undeveloped reserves of $336 million for the United States, $65 million for Canada, $87 million for Algeria and $70 million for Other International, which total $558 million.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Results of Operations for Producing Activities

The following schedule includes only the revenues from the production and sale of gas, oil, condensate and natural gas liquids (NGLs). Results of operations from gas, oil and NGLs marketing and gas gathering are excluded. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization (DD&A) allowances, after giving effect to permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas activities.

millions	**2002**	2001	2000
United States			
Net revenues from production			
Third-party sales of gas, oil, condensate and NGLs	**$1,581**	$2,237	$1,443
Gas and oil sold to consolidated affiliates	**804**	1,212	660
	2,385	3,449	2,103
Production (lifting) costs	**605**	671	418
Depreciation, depletion and amortization	**710**	792	429
Impairments related to oil and gas properties	**—**	1,701	—
	1,070	285	1,256
Income tax expense	**370**	81	437
Results of operations	**$ 700**	$ 204	$ 819
DD&A rate per net equivalent barrel	**$ 5.46**	$ 5.54	$ 5.16
Canada			
Net revenues from production			
Third-party sales of gas, oil, condensate and NGLs	**$ 633**	$ 760	$ 298
Gas and oil sold to consolidated affiliates	**12**	23	20
	645	783	318
Production (lifting) costs	**224**	203	85
Depreciation, depletion and amortization	**215**	225	76
Impairments related to oil and gas properties	**—**	808	—
	206	(453)	157
Income tax expense (benefit)	**87**	(193)	70
Results of operations	**$ 119**	$ (260)	$ 87
DD&A rate per net equivalent barrel	**$ 6.09**	$ 6.62	$ 6.12
Algeria			
Net revenues from production			
Third-party sales of oil	**$ 182**	$ 59	$ 85
Oil sold to consolidated affiliates	**392**	136	186
	574	195	271
Production (lifting) costs	**41**	21	23
Depreciation, depletion and amortization	**69**	24	26
	464	150	222
Income tax expense	**176**	54	137
Results of operations	**$ 288**	$ 96	$ 85
DD&A rate per net equivalent barrel	**$ 2.93**	$ 3.00	$ 2.78

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Results of Operations for Producing Activities (Continued)

millions	**2002**	2001	2000
Other International			
Net revenues from production			
Third-party sales of gas, oil, condensate and NGLs	**$ 131**	$ 193	$ 133
Oil sold to consolidated affiliates	**28**	—	—
	159	193	133
Production (lifting) costs	**68**	80	61
Depreciation, depletion and amortization	**62**	69	39
Impairments related to oil and gas properties	**39**	37	50
	(10)	7	(17)
Income tax expense (benefit)	**(4)**	3	(9)
Results of operations	**$ (6)**	$ 4	$ (8)
DD&A rate per net equivalent barrel	**$ 7.75**	$ 5.31	$ 5.36
Total			
Net revenues from production			
Third-party sales of gas, oil, condensate and NGLs	**$2,527**	$3,249	$1,959
Gas and oil sold to consolidated affiliates	**1,236**	1,371	866
	3,763	4,620	2,825
Production (lifting) costs	**938**	975	587
Depreciation, depletion and amortization	**1,056**	1,110	570
Impairments related to oil and gas properties	**39**	2,546	50
	1,730	(11)	1,618
Income tax expense (benefit)	**629**	(55)	635
Results of operations	**$1,101**	$ 44	$ 983
DD&A rate per net equivalent barrel	**$ 5.36**	$ 5.61	$ 5.08

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION
AND PRODUCTION ACTIVITIES
(Unaudited)

Oil and Gas Reserves

The following table shows internal estimates prepared by the Company's engineers of proved reserves and proved developed reserves, net of royalty interests, of natural gas, crude oil, condensate and NGLs owned at year-end and changes in proved reserves during the last three years. Volumes for natural gas are in billions of cubic feet (Bcf) at a pressure base of 14.73 pounds per square inch and volumes for oil, condensate and NGLs are in millions of barrels (MMBbls). Total volumes are in millions of barrels of oil equivalent (MMBOE). For this computation, one barrel is the equivalent of six thousand cubic feet of gas. NGLs are included with oil and condensate reserves and the associated shrinkage has been deducted from the gas reserves.

Algerian reserves are shown in accordance with the Production Sharing Agreement (PSA). The reserves include estimated quantities allocated to Anadarko for recovery of costs and Algerian taxes and Anadarko's net equity share after recovery of such costs. Other international reserves are shown in accordance with the respective PSA or risk service contract and are calculated using the economic interest method.

The Company's reserves increased in 2002 primarily from exploration and development drilling and corporate acquisitions, offset in part by production, downward revisions to prior estimates and divestitures. The downward revisions in 2002 were partially due to a downward price revision of 36 MMBOE in Venezuela. Under the terms of Anadarko's risk service contract with the national oil company of Venezuela, Anadarko earns a fee that is translated into barrels of oil based on current prices. This means that higher oil prices reduce the Company's reported oil reserves and production volumes from that project; however, reserve and production fluctuations due to the economic interest calculation have no impact on the value of the project. The Company's reserves increased in 2001 primarily from exploration and development drilling and corporate acquisitions, offset in part by production, divestitures and downward revisions to prior estimates due to low year-end prices. The Company's reserves increased in 2000 primarily from a corporate acquisition, exploration and development drilling, improved recovery and high gas prices at year-end 2000 compared to year-end 1999.

The Company emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data as well as production performance data. These estimates are reviewed and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in assumptions based on, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to uneconomic conditions.

Oil and Gas Reserves (Continued)

	Natural Gas (Bcf)				Oil, Condensate and NGLs (MMBbls)				
	U.S.	Canada	Other Int'l	Total	U.S.	Canada	Algeria	Other Int'l	Total
Proved Reserves									
December 31, 1999	2,507	—	—	2,507	284	—	289	—	573
Revisions of prior estimates	102	(30)	(5)	67	23	(5)	—	6	24
Extensions, discoveries and other additions	665	15	—	680	8	3	84	—	95
Improved recovery	30	—	—	30	9	—	—	—	9
Purchases in place	2,253	910	33	3,196	161	85	—	147	393
Sales in place	—	(2)	—	(2)	—	—	—	(1)	(1)
Production	(338)	(46)	(1)	(385)	(27)	(4)	(9)	(7)	(47)
December 31, 2000	5,219	847	27	6,093	458	79	364	145	1,046
Revisions of prior estimates	(172)	(17)	—	(189)	(23)	(3)	(12)	15	(23)
Extensions, discoveries and other additions	1,186	171	—	1,357	91	8	44	30	173
Improved recovery	(9)	2	—	(7)	(5)	9	—	—	4
Purchases in place	2	407	146	555	1	30	—	33	64
Sales in place	(5)	(48)	(26)	(79)	(1)	(1)	—	(45)	(47)
Production	(573)	(121)	(1)	(695)	(48)	(14)	(9)	(14)	(85)
December 31, 2001	**5,648**	**1,241**	**146**	**7,035**	**473**	**108**	**387**	**164**	**1,132**
Revisions of prior estimates	**78**	**(42)**	**(2)**	**34**	**33**	**(15)**	**5**	**(52)**	**(29)**
Extensions, discoveries and other additions	**445**	**303**	**—**	**748**	**51**	**8**	**3**	**—**	**62**
Improved recovery	**(6)**	**—**	**—**	**(6)**	**8**	**—**	**—**	**—**	**8**
Purchases in place	**86**	**1**	**—**	**87**	**60**	**—**	**—**	**13**	**73**
Sales in place	**(53)**	**(25)**	**—**	**(78)**	**(2)**	**(24)**	**—**	**—**	**(26)**
Production	**(505)**	**(135)**	**—**	**(640)**	**(45)**	**(13)**	**(23)**	**(8)**	**(89)**
December 31, 2002	**5,693**	**1,343**	**144**	**7,180**	**578**	**64**	**372**	**117**	**1,131**
Proved Developed Reserves									
December 31, 1999	1,672	—	—	1,672	134	—	61	—	195
December 31, 2000	4,424	720	16	5,160	355	59	98	85	597
December 31, 2001	4,247	1,028	—	5,275	321	79	154	72	626
December 31, 2002	**4,299**	**995**	**—**	**5,294**	**377**	**46**	**191**	**72**	**686**

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION
AND PRODUCTION ACTIVITIES (Continued)
(Unaudited)

Oil and Gas Reserves (Continued)

	Total (MMBOE)				
	U.S.	Canada	Algeria	Other Int'l	Total
Proved Reserves					
December 31, 1999	702	—	289	—	991
Revisions of prior estimates	39	(10)	—	6	35
Extensions, discoveries and other additions	118	6	84	—	208
Improved recovery	14	—	—	—	14
Purchases in place	537	237	—	152	926
Sales in place	—	—	—	(1)	(1)
Production	(83)	(13)	(9)	(7)	(112)
December 31, 2000	1,327	220	364	150	2,061
Revisions of prior estimates	(52)	(6)	(12)	15	(55)
Extensions, discoveries and other additions	290	36	44	30	400
Improved recovery	(6)	9	—	—	3
Purchases in place	1	99	—	57	157
Sales in place	(1)	(9)	—	(50)	(60)
Production	(144)	(34)	(9)	(14)	(201)
December 31, 2001	**1,415**	**315**	**387**	**188**	**2,305**
Revisions of prior estimates	**46**	**(23)**	**5**	**(51)**	**(23)**
Extensions, discoveries and other additions	**124**	**59**	**3**	**—**	**186**
Improved recovery	**8**	**—**	**—**	**—**	**8**
Purchases in place	**74**	**—**	**—**	**13**	**87**
Sales in place	**(11)**	**(28)**	**—**	**—**	**(39)**
Production	**(130)**	**(35)**	**(23)**	**(8)**	**(196)**
December 31, 2002	**1,526**	**288**	**372**	**142**	**2,328**
Proved Developed Reserves					
December 31, 1999	412	—	61	—	473
December 31, 2000	1,092	179	98	88	1,457
December 31, 2001	1,029	250	154	72	1,505
December 31, 2002	**1,093**	**212**	**191**	**72**	**1,568**

Discounted Future Net Cash Flows

Estimates of future net cash flows from proved reserves of gas, oil, condensate and NGLs were made in accordance with SFAS No. 69, ''Disclosures about Oil and Gas Producing Activities.'' The amounts were prepared by the Company's engineers and are shown in the following table. The estimates are based on prices at year-end. Gas prices are escalated only for fixed and determinable amounts under provisions in some contracts. Estimated future cash inflows are reduced by estimated future development, production, abandonment and dismantlement costs based on year-end cost levels, assuming continuation of existing economic conditions, and by estimated future income tax expense. Income tax expense, both U.S. and foreign, is calculated by applying the existing statutory tax rates, including any known future changes, to the pretax net cash flows giving effect to any permanent differences and reduced by the applicable tax basis. The effect of tax credits is considered in determining the income tax expense.

At December 31, 2002, the present value (discounted at 10%) of future net revenues from Anadarko's proved reserves was $21.1 billion, before income taxes, and $14.1 billion, after income taxes, (stated in accordance with the regulations of the SEC and the Financial Accounting Standards Board). The after income taxes increase of $6.1 billion or 76% in 2002 compared to 2001 is primarily due to significantly higher natural gas and crude oil prices at year-end 2002, additions of proved reserves related to successful drilling worldwide and corporate acquisitions.

The present value of future net revenues does not purport to be an estimate of the fair market value of Anadarko's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas. Significant changes in estimated reserve volumes or commodity prices could have a material effect on the Company's consolidated financial statements.

Under the full cost method of accounting, a non-cash charge to earnings related to the carrying value of the Company's oil and gas properties on a country-by-country basis may be required when prices are low. Whether the Company will be required to take such a charge depends on the prices for crude oil and natural gas at the end of any quarter, as well as the effect of both capital expenditures and changes to proved reserves during that quarter. If a non-cash charge were required, it would reduce earnings for the period and result in lower DD&A expense in future periods.

As a result of low oil and gas prices at September 30, 2001, Anadarko's capitalized costs of oil and gas properties in the United States, Canada and Argentina exceeded the ceiling limitation, and the Company recorded a $2.5 billion ($1.6 billion after taxes) non-cash write-down in the third quarter of 2001. The pre-tax write-down is reflected as additional accumulated DD&A in the Company's balance sheet.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

millions	**2002**	2001	2000
United States			
Future cash inflows	**$36,536**	$19,890	$57,027
Future production costs	**8,989**	6,072	8,175
Future development costs	**2,142**	1,759	1,182
Future net cash flows before income taxes	**25,405**	12,059	47,670
10% annual discount for estimated timing of cash flows	**12,695**	5,805	22,911
Discounted future net cash flows before income taxes	**12,710**	6,254	24,759
Future income taxes, net of 10% annual discount	**4,113**	1,764	8,546
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**8,597**	4,490	16,213
Canada			
Future cash inflows	**6,609**	4,325	8,720
Future production costs	**1,478**	1,165	866
Future development costs	**516**	425	288
Future net cash flows before income taxes	**4,615**	2,735	7,566
10% annual discount for estimated timing of cash flows	**2,048**	1,030	3,261
Discounted future net cash flows before income taxes	**2,567**	1,705	4,305
Future income taxes, net of 10% annual discount	**821**	465	1,880
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**1,746**	1,240	2,425
Algeria			
Future cash inflows	**11,597**	7,466	8,410
Future production costs	**1,209**	1,113	1,011
Future development costs	**478**	313	408
Future net cash flows before income taxes	**9,910**	6,040	6,991
10% annual discount for estimated timing of cash flows	**5,127**	3,089	3,807
Discounted future net cash flows before income taxes	**4,783**	2,951	3,184
Future income taxes, net of 10% annual discount	**1,747**	1,109	1,108
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**$ 3,036**	$ 1,842	$ 2,076

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Continued)

millions	**2002**	2001	2000
Other International			
Future cash inflows	**$ 2,933**	$ 2,242	$ 2,631
Future production costs	**709**	537	637
Future development costs	**432**	512	394
Future net cash flows before income taxes	**1,792**	1,193	1,600
10% annual discount for estimated timing of cash flows	**747**	562	705
Discounted future net cash flows before income taxes	**1,045**	631	895
Future income taxes, net of 10% annual discount	**314**	172	204
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**731**	459	691
Total			
Future cash inflows	**57,675**	33,923	76,788
Future production costs	**12,385**	8,887	10,689
Future development costs	**3,568**	3,009	2,272
Future net cash flows before income taxes	**41,722**	22,027	63,827
10% annual discount for estimated timing of cash flows	**20,617**	10,486	30,684
Discounted future net cash flows before income taxes	**21,105**	11,541	33,143
Future income taxes, net of 10% annual discount	**6,995**	3,510	11,738
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**$14,110**	$ 8,031	$21,405

Expected future development costs to develop proved undeveloped reserves as of December 31, 2002 in the United States are $970 million, $522 million and $190 million for 2003, 2004 and 2005, respectively. For Canada, the expected costs are $130 million, $76 million and $116 million for 2003, 2004 and 2005, respectively. For Algeria, the expected costs are $71 million, $64 million and $124 million for 2003, 2004 and 2005, respectively. For Other International, the expected costs are $54 million, $85 million and $41 million for 2003, 2004 and 2005, respectively. In total, the expected costs are $1.2 billion, $747 million and $471 million for 2003, 2004 and 2005, respectively.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

millions	**2002**	2001	2000
United States			
Beginning of year	**$ 4,490**	$ 16,213	$ 2,794
Sales and transfers of oil and gas produced, net of production costs	**(1,780)**	(2,778)	(1,685)
Net changes in prices and production costs	**5,935**	(19,309)	7,556
Changes in estimated future development costs	**(206)**	183	(119)
Extensions, discoveries, additions and improved recovery, less related costs	**999**	624	2,719
Development costs incurred during the period	**331**	337	126
Revisions of previous quantity estimates	**441**	(453)	114
Purchases of minerals in place	**532**	17	11,841
Sales of minerals in place	**(82)**	(5)	(1)
Accretion of discount	**625**	2,476	386
Net change in income taxes	**(2,349)**	6,782	(7,476)
Other	**(339)**	403	(42)
End of year	**8,597**	4,490	16,213
Canada			
Beginning of year	**1,240**	2,425	—
Sales and transfers of oil and gas produced, net of production costs	**(421)**	(580)	(233)
Net changes in prices and production costs	**774**	(3,319)	—
Changes in estimated future development costs	**(70)**	2	—
Extensions, discoveries, additions and improved recovery, less related costs	**541**	279	101
Development costs incurred during the period	**157**	101	—
Revisions of previous quantity estimates	**(259)**	(38)	(165)
Purchases of minerals in place	**3**	593	4,568
Sales of minerals in place	**(96)**	(56)	—
Accretion of discount	**171**	431	—
Net change in income taxes	**(356)**	1,415	(1,880)
Other	**62**	(13)	34
End of year	**1,746**	1,240	2,425
Algeria			
Beginning of year	**1,842**	2,076	1,588
Sales and transfers of oil produced, net of production costs	**(533)**	(174)	(248)
Net changes in prices and production costs	**2,316**	(554)	(330)
Changes in estimated future development costs	**(314)**	—	—
Extensions, discoveries, additions and improved recovery, less related costs	**85**	56	901
Development costs incurred during the period	**122**	164	135
Accretion of discount	**295**	318	250
Net change in income taxes	**(638)**	(1)	(197)
Other	**(139)**	(43)	(23)
End of year	**$ 3,036**	$ 1,842	$ 2,076

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Continued)

millions	**2002**	2001	2000
Other International			
Beginning of year	**$ 459**	$ 691	$ —
Sales and transfers of oil and gas produced, net of production costs	**(91)**	(113)	(72)
Net changes in prices and production costs	**757**	(402)	—
Changes in estimated future development costs	**1**	32	—
Extensions, discoveries, additions and improved recovery, less related costs	**—**	109	—
Development costs incurred during the period	**88**	87	—
Revisions of previous quantity estimates	**(520)**	75	—
Purchases of minerals in place	**117**	188	967
Sales of minerals in place	**—**	(199)	—
Accretion of discount	**64**	90	—
Net change in income taxes	**(142)**	32	(204)
Other	**(2)**	(131)	—
End of year	**731**	459	691
Total			
Beginning of year	**8,031**	21,405	4,382
Sales and transfers of oil and gas produced, net of production costs	**(2,825)**	(3,645)	(2,238)
Net changes in prices and production costs	**9,782**	(23,584)	7,226
Changes in estimated future development costs	**(589)**	217	(119)
Extensions, discoveries, additions and improved recovery, less related costs	**1,625**	1,068	3,721
Development costs incurred during the period	**698**	689	261
Revisions of previous quantity estimates	**(338)**	(416)	(51)
Purchases of minerals in place	**652**	798	17,376
Sales of minerals in place	**(178)**	(260)	(1)
Accretion of discount	**1,155**	3,315	636
Net change in income taxes	**(3,485)**	8,228	(9,757)
Other	**(418)**	216	(31)
End of year	**$ 14,110**	$ 8,031	$ 21,405

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following table shows summary quarterly financial data for 2002 and 2001. Certain amounts for prior periods have been reclassified to conform to the current presentation. See Note 1.

millions except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2002				
Revenues	**$ 790**	**$1,002**	**$ 951**	**$1,117**
Operating income, pretax	**204**	**364**	**363**	**494**
Net income before cumulative effect of change in accounting principle	**$ 89**	**$ 241**	**$ 190**	**$ 311**
Net income available to common stockholders before cumulative effect of change in accounting principle	**$ 88**	**$ 239**	**$ 189**	**$ 309**
Net income available to common stockholders	**$ 88**	**$ 239**	**$ 189**	**$ 309**
EPS - before cumulative effect of change in accounting principle - basic	**$ 0.35**	**$ 0.96**	**$ 0.76**	**$ 1.25**
EPS - before cumulative effect of change in accounting principle - diluted	**$ 0.34**	**$ 0.93**	**$ 0.74**	**$ 1.21**
EPS - basic	**$ 0.35**	**$ 0.96**	**$ 0.76**	**$ 1.25**
EPS - diluted	**$ 0.34**	**$ 0.93**	**$ 0.74**	**$ 1.21**
Average number common shares outstanding - basic	**248**	**248**	**249**	**249**
Average number common shares outstanding - diluted	**263**	**259**	**258**	**258**
2001				
Revenues	$1,588	$1,322	$ 1,010	$ 798
Operating income (loss), pretax[1]	979	620	(2,169)[2]	207
Net income (loss) before cumulative effect of change in accounting principle[1]	$ 664	$ 402	$(1,351)[2]	$ 109
Net income (loss) available to common stockholders before cumulative effect of change in accounting principle[1]	$ 661	$ 401	$(1,353)[2]	$ 108
Net income (loss) available to common stockholders[1]	$ 656	$ 401	$(1,353)[2]	$ 108
EPS - before cumulative effect of change in accounting principle - basic	$ 2.64	$ 1.60	$ (5.41)[2]	$ 0.43
EPS - before cumulative effect of change in accounting principle - diluted	$ 2.52	$ 1.50	$ (5.41)[2]	$ 0.41
EPS - basic	$ 2.62	$ 1.60	$ (5.41)[2]	$ 0.43
EPS - diluted	$ 2.50	$ 1.50	$ (5.41)[2]	$ 0.41
Average number common shares outstanding - basic	250	251	250	249
Average number common shares outstanding - diluted	263	268	250	266

[1] In January 2002, the Company discontinued the amortization of goodwill in accordance with Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets." Goodwill amortization expensed in the first, second, third and fourth quarters of 2001 was $17 million, $19 million, $21 million and $16 million, respectively, both before and after taxes. See Note 3.

[2] Anadarko's operating loss for the third quarter 2001 includes a charge of $2.5 billion ($1.6 billion after taxes) for impairments of the carrying value of proved oil and gas properties primarily in the United States, Canada and Argentina as a result of low oil and gas prices at the end of the quarter.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

See *Anadarko Board of Directors, Guidelines and Codes* and *Section 16(a) Beneficial Ownership Reporting Compliance* in the Anadarko Petroleum Corporation Proxy Statement, dated March 24, 2003 (Proxy Statement), which is incorporated herein by reference.

See list of *Executive Officers of the Registrant* appearing under Item 4 of this Form 10-K.

Item 11. Executive Compensation

See *Board of Directors* and *Executive Compensation* in the Proxy Statement, which is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

See *Stock Ownership* in the Proxy Statement, which is incorporated herein by reference.

See *Equity Compensation Plan Table* appearing under Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions

See *Board of Directors* and *Transactions with Management* in the Proxy Statement, which is incorporated herein by reference.

Item 14. Controls and Procedures

Anadarko's Chief Executive Officer and Chief Financial Officer (Certifying Officers) performed an evaluation of the Company's disclosure controls and procedures within 90 days of the filing of this Form 10-K. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Based on this evaluation, the Certifying Officers have concluded that the Company's disclosure controls and procedures are effective. In addition, there have been no significant changes in the internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

PART IV

Item 15. Exhibits and Reports on Form 8-K

(a) The following documents are filed as a part of this report or incorporated by reference:

(1) The consolidated financial statements of Anadarko Petroleum Corporation are listed on the Index to this report, page 53.

(2) Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description	Originally Filed as Exhibit	File Number
2(a)	Agreement and Plan of Merger dated as of April 2, 2000, among Anadarko, Subcorp and Anadarko Holding Company	2.1 to Form 8-K dated April 2, 2000	1-8968
3(a)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated August 28, 1986	4(a) to Form S-3 dated May 9, 2001	333-60496
(b)	By-laws of Anadarko Petroleum Corporation, as amended	3(e) to Form 10-Q for quarter ended September 30, 2000	1-8968
(c)	Certificate of Amendment of Anadarko's Restated Certificate of Incorporation	4.1 to Form 8-K dated July 28, 2000	1-8968
4(a)	Certificate of Designation of 5.46% Cumulative Preferred Stock, Series B	4(a) to Form 8-K dated May 6, 1998	1-8968
(b)	Rights Agreement, dated as of October 29, 1998, between Anadarko Petroleum Corporation and The Chase Manhattan Bank	4.1 to Form 8-A dated October 30, 1998	1-8968
(c)	Amendment No. 1 to Rights Agreement, dated as of April 2, 2000 between Anadarko and the Rights Agent	2.4 to Form 8-K dated April 2, 2000	1-8968
Director and Executive Compensation Plans and Arrangements			
10(b)(i)	Anadarko Petroleum Corporation 1988 Stock Option Plan for Non-Employee Directors	19(b) to Form 10-Q for quarter ended September 30, 1988	1-8968
(ii)	Anadarko Petroleum Corporation Amended and Restated 1988 Stock Option Plan for Non-Employee Directors	99 — Attachment A to Form 10-K for year ended December 31, 1993	1-8968
(iii)	Amendment to Anadarko Petroleum Corporation 1988 Stock Option Plan for Non-Employee Directors	10(b)(vii) to Form 10-K for year ended December 31, 1997	1-8968
(iv)	Second Amendment to Anadarko Petroleum Corporation 1988 Stock Option Plan for Non-Employee Directors	10(b)(viii) to Form 10-K for year ended December 31, 1997	1-8968
(v)	1998 Director Stock Plan of Anadarko Petroleum Corporation, effective January 30, 1998	99 — Attachment A to Form 10-K for year ended December 31, 1997	1-8968

Exhibit Number	Description	Originally Filed as Exhibit	File Number
10(b)(vi)	Anadarko Petroleum Corporation and Participating Affiliates and Subsidiaries Annual Override Pool Bonus Plan, as amended October 6, 1986	19(c)(ix) to Form 10-Q for quarter ended September 30, 1986	1-8968
(vii)	Second Amendment to Anadarko Petroleum Corporation and Participating Affiliates and Subsidiaries Annual Override Pool Bonus Plan	10(b)(ii) to Form 10-K for year ended December 31, 1987	1-8968
(viii)	Restatement of the Anadarko Petroleum Corporation 1987 Stock Option Plan (and Related Agreement)	Post Effective Amendment No. 1 to Forms S-8 and S-3, Anadarko Petroleum Corporation 1987 Stock Option Plan	33-22134
(ix)	First Amendment to Restatement of the Anadarko Petroleum Corporation 1987 Stock Option Plan	10(b)(xii) to Form 10-K for year ended December 31, 1997	1-8968
(x)	1993 Stock Incentive Plan	10(b)(xii) to Form 10-K for year ended December 31, 1993	1-8968
(xi)	First Amendment to Anadarko Petroleum Corporation 1993 Stock Incentive Plans	99 — Attachment A to Form 10-K for year ended December 31, 1996	1-8968
(xii)	Second Amendment to Anadarko Petroleum Corporation 1993 Stock Incentive Plans	10(b)(xv) to Form 10-K for year ended December 31, 1997	1-8968
(xiii)	Anadarko Petroleum Corporation 1993 Stock Incentive Plan Stock Option Agreement	10(a) to Form 10-Q for quarter ended March 31, 1996	1-8968
(xiv)	Form of Anadarko Petroleum Corporation 1993 Stock Incentive Plan Stock Option Agreement	10(b)(xvii) to Form 10-K for year ended December 31, 1997	1-8968
(xv)	Form of Anadarko Petroleum Corporation 1993 Stock Incentive Plan Restricted Stock Agreement	10(b)(xviii) to Form 10-K for year ended December 31, 1997	1-8968
(xvi)	Anadarko Petroleum Corporation 1999 Stock Incentive Plan	99 — Attachment A to Form 10-K for year ended December 31, 1998	1-8968
(xvii)	Amendment to 1999 Stock Incentive Plan, as of July 1, 2000	10(b)(xxii) to Form 10-K for year ended December 31, 2000	1-8968
(xviii)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Stock Option Agreement	10(b)(xxiii) to Form 10-K for year ended December 31, 1999	1-8968
(xix)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Agreement	10(b)(xxiv) to Form 10-K for year ended December 31, 1999	1-8968
(xx)	Annual Incentive Bonus Plan	10(b)(xiii) to Form 10-K for year ended December 31, 1993	1-8968

Exhibit Number	Description	Originally Filed as Exhibit	File Number
10(b)(xxi)	First Amendment to Anadarko Petroleum Corporation Annual Incentive Bonus Plan	99 — Attachment B to Form 10-K for year ended December 31, 1998	1-8968
*(xxii)	Second Amendment to Anadarko Petroleum Corporation Annual Incentive Bonus Plan		
(xxiii)	Key Employee Change of Control Contract	10(b)(xxii) to Form 10-K for year ended December 31, 1997	1-8968
(xxiv)	First Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract	10(b) to Form 10-Q for quarter ended September 30, 2000	1-8968
(xxv)	Anadarko Retirement Restoration Plan, effective January 1, 1995	10(b)(xix) to Form 10-K for year ended December 31, 1995	1-8968
(xxvi)	Anadarko Savings Restoration Plan, effective January 1, 1995	10(b)(xx) to Form 10-K for year ended December 31, 1995	1-8968
(xxvii)	Amendment to Amended and Restated Anadarko Savings Restoration Plan	10(b)(xxxi) to Form 10-K for year ended December 31, 1997	1-8968
(xxviii)	Plan Agreement for the Management Life Insurance Plan between Anadarko Petroleum Corporation and each Eligible Employee, effective July 1, 1995	10(b)(xxi) to Form 10-K for year ended December 31, 1995	1-8968
(xxix)	Anadarko Petroleum Corporation Estate Enhancement Program	10(b)(xxxiv) to Form 10-K for year ended December 31, 1998	1-8968
(xxx)	Estate Enhancement Program Agreement between Anadarko Petroleum Corporation and Eligible Executives	10(b)(xxxv) to Form 10-K for year ended December 31, 1998	1-8968
(xxxi)	Estate Enhancement Program Agreements effective November 29, 2000	10(b)(xxxxii) to Form 10-K for year ended December 31, 2000	1-8968
*(xxxii)	Anadarko Petroleum Corporation Management Life Insurance Plan		
*(xxxiii)	Management Disability Plan — Plan Summary		
*12	Computation of Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Stock Dividends		
*13	Portions of the Anadarko Petroleum Corporation 2002 Annual Report to Stockholders		
*21	List of Significant Subsidiaries		
*23.1	Consent of KPMG LLP		
*23.2	Consent of Ryder Scott Company		
*24	Power of Attorney		

Exhibit Number	Description	Originally Filed as Exhibit	File Number
*99.1	Anadarko Petroleum Corporation Proxy Statement, dated March 24, 2003	Filed on March 13, 2003	
*99.2	Certification of Chief Executive Officer and Chief Financial Officer		
*99.3	Ryder Scott Company Report		

The total amount of securities of the registrant authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to the Securities and Exchange Commission.

(b) Reports on Form 8-K

A report on Form 8-K dated October 1, 2002 was filed in which the earliest event reported was September 29, 2002. This event was reported under Item 5 "Other Events" and Item 7c. "Exhibits."

A report on Form 8-K dated November 1, 2002 was filed in which the earliest event reported was October 31, 2002. This event was reported under Item 5 "Other Events" and Item 7c. "Exhibits."

A report on Form 8-K dated December 6, 2002 was filed in which the earliest event reported was December 6, 2002. This event was reported under Item 5 "Other Events" and Item 7c. "Exhibits."

A report on Form 8-K dated December 13, 2002 was filed in which the earliest event reported was December 13, 2002. This event was reported under Item 5 "Other Events and Regulation FD Disclosure" and Item 7c. "Exhibits."

A report on Form 8-K dated December 20, 2002 was filed in which the earliest event reported was December 20, 2002. This event was reported under Item 5 "Other Events and Regulation FD Disclosure" and Item 7c. "Exhibits."

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ANADARKO PETROLEUM CORPORATION

March 13, 2003

By: MICHAEL E. ROSE
(Michael E. Rose, Executive Vice President and Chief Financial Officer)

Pursuant to the requirements of the securities exchange act of 1934, this Report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 13, 2003.

Name and Signature	Title
(i) Principal executive officer:*	
JOHN N. SEITZ (John N. Seitz)	President and Chief Executive Officer
(ii) Principal financial officer:*	
MICHAEL E. ROSE (Michael E. Rose)	Executive Vice President and Chief Financial Officer
(iii) Principal accounting officer:*	
DIANE L. DICKEY (Diane L. Dickey)	Vice President and Controller
(iv) Directors:*	
ROBERT J. ALLISON, JR. CONRAD P. ALBERT LARRY BARCUS RONALD BROWN JAMES L. BRYAN JOHN R. BUTLER, JR. PRESTON M. GEREN III JOHN R. GORDON JOHN W. PODUSKA, SR., PH.D. JOHN N. SEITZ	

* Signed on behalf of each of these persons and on his own behalf:

By MICHAEL E. ROSE
(Michael E. Rose, Attorney-in-Fact)

CERTIFICATIONS

I, John N. Seitz, certify that:

1. I have reviewed this annual report on Form 10-K of Anadarko Petroleum Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the ''Evaluation Date''); and

   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 13, 2003

JOHN N. SEITZ

President and Chief Executive Officer

CERTIFICATIONS

I, Michael E. Rose, certify that:

1. I have reviewed this annual report on Form 10-K of Anadarko Petroleum Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the ''Evaluation Date''); and

   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 13, 2003

MICHAEL E. ROSE

Executive Vice President and Chief Financial Officer