CABOT OIL & GAS CORP
Form 10-K
February 22, 2002

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 fiscal year ended December 31, 2001

Commission file number 1-10447

CABOT OIL & GAS CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	04-3072771
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

1200 Enclave Parkway, Houston, Texas 77077
(Address of principal executive offices including ZIP code)

(281) 589-4600
(Registrant's telephone number)

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

Title of each class	Name of each exchange on which registered
Class A Common Stock, par value $.10 per share	New York Stock Exchange
Rights to Purchase Preferred Stock	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 and (2) has been subject to such filing requirements for the past 90 days.

Yes X No _______

Indicate by check mark if 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 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 [__].

The aggregate market value of Class A Common Stock, par value $.10 per share ("Common Stock"), held by non-affiliates (based upon the closing sales price on the New York Stock Exchange on January 31, 2002), was approximately $636,620,000. As of January 31, 2002, there were 31,905,097 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held May 2, 2002, are incorporated herein by reference in Items 10, 11, 12 and 13 of Part III of this report.

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The statements regarding future financial and operating performance and results, market prices, future hedging activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "forecast," "predict," "may," "should," "could" and similar expressions are also intended to identify forward-looking statements. These statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including regional basis differentials) of natural gas and oil, results for future drilling and marketing activity, future production and costs, and other factors detailed in this document and in our other Securities and Exchange Commission filings. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual outcomes may vary materially from those included in this document.

PART I

ITEM 1. BUSINESS

OVERVIEW

Cabot Oil & Gas is an independent oil and gas company engaged in the exploration, development, acquisition and exploitation of oil and gas properties located in four principal areas of the United States:

.. The onshore Texas and Louisiana Gulf Coast

.. The Rocky Mountains
.. The Mid-Continent or Anadarko Basin
.. Appalachia

Administratively, we operate in three regions - the Gulf Coast region, the Western region, which is comprised of the Rocky Mountains and Mid-Continent areas, and the Appalachian region.

In 2001, we enjoyed a strong energy commodity price environment for most of the year bolstered by gains realized on price hedges which were placed on about 44% of our production for the first nine months of 2001 natural gas production near the peak of the market in December 2000. Drilling successes, most notably in south Louisiana, over the past two years served to increase our 2001 production by 12% over 2000. While continuing to develop our existing fields and exploring for new discoveries, we took advantage of our strong cash flow and invested for the future. Most significantly, we acquired Cody Company in August 2001. With this transaction, we expanded and improved our development inventory and added 11 exploration prospects. In addition, we expanded our acreage position with a $12 million acquisition in the Rocky Mountains and added significantly to our seismic database in both the Rocky Mountains and Gulf Coast. The five months of production from the acquired Cody Company properties increased our annual production by an additional 9% over 2000, for a combined 21% production increase year-over-year.

The purchase of Cody Company was the largest acquisition in our Company's history. We paid $231.2 million in cash and common stock for all of the outstanding common stock of Cody Company. Substantially all of the proved reserves of Cody Company are located in the onshore Gulf Coast region, a strategic growth area for us. As of December 31, 2001, these properties contributed 39.1 Mmcfe of production per day and contained 92 proved undeveloped drilling locations.

In 2001, 87% of the wells that we drilled were successful. Drilling was successful on 40% of our 2001 exploration wells, as we tested new ideas and worked on building a foundation for the future. Our 2001 capital and exploration spending included $39.1 million for seismic data and lease acquisition. This spending will support our exploration and development drilling programs in 2002 and beyond. As we enter 2002 energy commodity prices have softened. We will concentrate our 2002 capital spending program on projects offering the prospect of acceptable risk and the strongest economics. As in the past, we will use the cash flow from our long-lived Appalachian and Mid-Continent natural gas reserves to fund our exploration and development efforts in the Gulf Coast and Rocky Mountain areas. We believe these two core producing areas offer more value, accretive reserve and production growth and higher rates of return on equity.

Our proved reserves totaled approximately 1.2 Tcfe at December 31, 2001, of which 90% was natural gas. This reserve level represents a 13% increase over the prior year end. The increase is due primarily to the Cody acquisition, which combined with drilling activities, replaced production by 268%. The Gulf Coast region now represents 26% of our total proved reserves, up from 14% at the end of 2000.

Net income of $47.1 million, or $1.56 per share, was the highest annual level of earnings that we have ever achieved. Cash flow from operations in 2001 of $250.4 million was also a record, and represented a 110% increase over last year. The strong commodity price environment combined with strategic price collars were the main factors in this year's financial success. Production improvements as discussed above also helped boost our earnings. Daily production averaged 199 Mmcfe per day during the first seven months of the year before increasing to approximately

255 Mmcfe per day in August with the acquisition of Cody Company. Overall, including the Cody acquisition and additional successes in south Louisiana, production averaged 222 Mmcfe per day in 2001. Development drilling on the Etouffee field in south Louisiana has expanded producing wells to six, two of which were drilled in 2001. This field, which is now fully developed, remains our largest producer and at December 31, 2001 was producing 137 Mmcfe per day (33 Mmcfe per day net to us).

The following table presents certain information as of December 31, 2001.

		West			
	Gulf Coast	Rocky Mountains	Mid-Continent	Total West	Appa
Proved Reserves at Year End (Bcfe)					
Developed	224.1	176.8	171.1	347.9	
Undeveloped	76.2	50.6	28.0	78.6	
Total	300.3	227.4	199.1	426.5	
Average Daily Production (Mmcfe per day)	97.8	45.9	30.2	76.1	
Reserve Life Index (in years) /(1)/	8.4	13.6	18.1	15.4	
Gross Wells	1,013	528	695	1,223	
Net Wells /(2)/	613.2	233.0	457.7	690.7	2,
Percent Wells Operated	72.1%	49.1%	74.1%	63.3%	
Net Acreage					
Developed	103,836	85,058	180,981	266,039	74
Undeveloped	44,008	343,565	4,868	348,433	22
Total	147,844	428,623	185,849	614,472	96

/(1)/ Reserve Life Index is equal to year-end reserves divided by annual production.

/(2)/ The term "net" as used in "net acreage" or "net production" throughout this document refers to amounts that include only acreage or production that is owned by Cabot Oil & Gas and produced to its interest, less royalties and production due others. "Net wells" represents our working interest share of each well.

GULF COAST REGION

Our exploration, development and production activities in Gulf Coast region are concentrated in south Louisiana and south Texas. A regional office in Houston manages operations. Principal producing intervals are in the Wilcox and Vicksburg formations in Texas and the Miocene age formations in Louisiana at depths ranging from 3,000 to 20,500 feet. Capital and exploration expenditures made with cash and common stock were $352.1 million in 2001 or 78% of our total 2001 capital and exploration expenditures, and $66.0 million for 2000. The cash and common stock portion of the August 2001 acquisition of Cody Company accounted for $231.2 million of this amount, which did not include a non-cash deferred tax gross-up of $78.0 million. Our drilling and acquisition program has increased average daily production in the region from 15.6 Mmcfe per day in

1994, when we acquired our first Gulf Coast properties from Washington Energy, to 131.6 Mmcfe per day in December 2001. Of this production rate, 39.1 Mmcfe per day was associated with the newly acquired Cody properties and the remaining primarily represents production growth from our drilling activity. For 2002, we have budgeted $56.9 million (54% of our total 2002 capital budget) for capital expenditures in the region. Our 2002 Gulf Coast drilling program will emphasize our exploration opportunities and development drilling on the prospects acquired in the Cody acquisition.

We had 1,013 wells (613.2 net) in the Gulf Coast region as of December 31, 2001, of which 730 wells are operated by us. Average net daily production in 2001 was 97.8 Mmcfe, up from 49.5 Mmcfe in 2000 due both to drilling success in south Louisiana and to the Cody acquisition. At December 31, 2001, we had 300.3 Bcfe of proved reserves (67% natural gas) in the Gulf Coast region, which represented 26% of our total proved reserves.

In 2001, we drilled 35 wells (14.7 net) in the Gulf Coast region, of which 20 wells (7.76 net) were development wells. The south Louisiana Etouffee prospect and our new discoveries in the Augen field in south

Louisiana and Red Fish Bay prospects in south Texas, together with the Cody acquisition, contributed to the significant growth in net proved reserves. In the Gulf Coast region, we plan to drill 19 wells in 2002 of which seven are on prospects acquired from Cody.

At December 31, 2001, we had 147,844 net acres in the region, including 103,836 net developed, and we had identified 97 proved undeveloped drilling locations of which 92 were part of the Cody acquisition.

Our principal markets for Gulf Coast region natural gas are in the industrialized Gulf Coast area and the northeastern United States. Our marketing subsidiary, Cabot Oil & Gas Marketing Corporation, purchases all of our natural gas production in the Gulf Coast region. The marketing subsidiary sells the natural gas to intrastate pipelines, natural gas processors and marketing companies.

Currently, approximately 75% of our natural gas sales volumes in the Gulf Coast region are sold at index-based prices under contracts with terms of one to three years. The remaining 25% of our sales volumes are sold at index-based prices under short-term agreements. From time to time when we believe market conditions are favorable, we may implement financial hedges on a portion of our production in an attempt to reduce our exposure to price volatility. The Gulf Coast properties are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

We also produce and market approximately 6,500 barrels per day of crude oil/condensate in the Gulf Coast region at market responsive prices.

WESTERN REGION

Our activities in the Western region are managed by a regional office in Denver. At December 31, 2001, we had 426.5 Bcfe of proved reserves (96% natural gas) in the Western region, constituting 37% of our total proved reserves.

Rocky Mountains

Our Rocky Mountains activities are concentrated in the Green River Basin and Washakie Basin of Wyoming. Since our initial acquisition in the area in 1994 from Washington Energy, we have increased reserves from 171.6 Bcfe at December 31, 1994, to 227.4 Bcfe at December 31, 2001. Capital and exploration expenditures were $42.9 million for 2001, or 9% of our total 2001 capital and exploration expenditures, and $23.9 million for 2000. In addition to drilling activity, approximately $15.4 million was expended in 2001 for lease acquisition and seismic data to provide exploration and development opportunities in the future. For 2002, we have budgeted $19.4 million (19% of our total 2002 capital budget) for capital expenditures in the area. The 2002 drilling program consists of several new exploration plays complemented by development drilling.

We had 528 wells (233.0 net) in the Rocky Mountains area as of December 31, 2001, of which 259 wells are operated by us. Principal producing intervals in the Rocky Mountains area are in the Almond, Frontier and Dakota formations at depths ranging from 9,000 to 13,500 feet. Average net daily production in the Rocky Mountains during 2001 was 45.9 Mmcfe.

In 2001, we drilled 31 wells (15.4 net) in the Rocky Mountains, of which 26 wells (11.5 net) were development and extension wells. In 2002, we plan to drill 41 wells.

At December 31, 2001, we had 428,623 net acres in the area, including 85,058 net developed acres, and we had identified 82 proved undeveloped drilling locations.

Mid-Continent

Our Mid-Continent activities are concentrated in the Anadarko Basin in southwestern Kansas, Oklahoma and the panhandle of Texas. Capital and exploration expenditures were $11.5 million for 2001, or 3% of our total 2001 capital and exploration expenditures, and $7.6 million for 2000. For 2002, we have budgeted $8.2 million (8% of our total 2002 capital budget) for capital expenditures in the area.

As of December 31, 2001, we had 695 wells (457.7 net) in the Mid-Continent area, of which 515 wells are operated by us. Principal producing intervals in the Mid-Continent are in the Chase, Morrow, Red Fork and Chester formations at depths ranging from 1,500 to 14,000 feet. Average net daily production in 2001 was 30.2 Mmcfe. At December 31, 2001, we had 199.1 Bcfe of proved reserves (97% natural gas) in the Mid-Continent area, 17% of our total proved reserves.

In 2001, we drilled 25 wells (17.2 net) in the Mid-Continent, all of which were development and extension wells. In 2002, we plan to drill 17 wells.

At December 31, 2001, we had 185,849 net acres in the area, including 180,981 net developed acres, and we had identified 62 proved undeveloped drilling locations.

Western Region Marketing

Our principal markets for Western region natural gas are in the northwestern, midwestern and northeastern United States. Cabot Oil & Gas Marketing purchases all of our natural gas production in the Western region. This marketing subsidiary sells the natural gas to power generators, natural gas processors, local distribution companies, industrial customers and marketing companies.

Currently, approximately 86% of our natural gas production in the Western region is sold primarily under contracts with a term of one to three years at index-based prices. Another 12% of the natural gas production is sold under short-term arrangements at index-based prices and the remaining 2% is sold under certain fixed-price contracts. From time to time when we believe market conditions are favorable, we may implement financial hedges on a portion of our production in an attempt to reduce our exposure to price volatility.. The Western region properties are connected to the majority of the midwestern and northwestern interstate and intrastate pipelines, affording us access to multiple markets.

In December 1999, we negotiated the buyout of a long-term, fixed price sales contract that covered approximately 20% of the Western region natural gas production and was due to expire in June 2008. We received a payment of $12 million as part of this contract buyout agreement. This contract was then replaced with a fixed price sales contract that expired in April 2001. The fixed natural gas sales price in both the original natural gas sales contract and the replacement sales contract was below the market price at year end 2000. After April 2001, this production was sold at market responsive prices.

We currently also produce and market approximately 600 barrels of crude oil/condensate per day in the Western region at market responsive prices.

APPALACHIAN REGION

Our Appalachian activities are concentrated in West Virginia, Pennsylvania, Ohio and Virginia. In this region, our assets include a large undeveloped acreage position, a high concentration of wells, natural gas gathering and pipeline systems, and storage capacity. We have achieved a drilling success rate of 89% in the region since 1991. Capital and exploration expenditures were $44.1 million for 2001, or 10% of our total 2001 capital spending, and $21.5 million for 2000. For 2002, we have budgeted $18.5 million (18% of our total 2002 capital budget) for capital expenditures in the region.

At December 31, 2001, we had 2,362 wells (2,190.9 net), of which 2,281 wells are operated by us. There are multiple producing intervals that include the Devonian Shale, Oriskany, Berea and Big Lime formations at depths

primarily ranging from 1,500 to 9,000 feet. Average net daily production in 2001 was 48.4 Mmcfe. While natural gas production volumes from Appalachian reservoirs are relatively low on a per-well basis compared to other areas of the United States, the productive life of Appalachian reserves is relatively long. At December 31, 2001, we had 427.3 Bcfe of proved reserves (substantially all natural gas) in the Appalachian region, constituting 37% of our total proved reserves. This region is managed from our office in Charleston, West Virginia.

In 2001, we drilled 117 wells (106.3 net) in the Appalachian region, of which 107 wells (97.0 net) were development wells. In 2002, we plan to drill 44 wells.

At December 31, 2001, we had 964,520 net acres in the region, including 743,204 net developed, and we had identified 292 proved undeveloped drilling locations.

Ancillary to our exploration and production operations, we operate a number of gas gathering and transmission pipeline systems, made up of approximately 2,500 miles of pipeline with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2001. The majority of our pipeline infrastructure in West Virginia is regulated by the Federal Energy Regulatory Commission (FERC). As such, the transportation rates and terms of service of our pipeline subsidiary, Cranberry Pipeline Corporation, are subject to the rules and regulations of the FERC. Our natural gas gathering and transmission pipeline systems enable us to connect new wells quickly and to transport natural gas from the wellhead directly to interstate pipelines, local distribution companies and industrial end users. Control of our gathering and transmission pipeline systems also enables us to purchase, transport and sell natural gas produced by third parties. In addition, we can engage in development drilling without relying upon third parties to transport our natural gas and incur only the incremental costs of pipeline and compressor additions to our system.

We have two natural gas storage fields located in West Virginia with a combined working capacity of approximately 4 Bcf. We use these storage fields to take advantage of the seasonal variations in the demand for natural gas and the higher prices typically associated with winter natural gas sales, while maintaining production at a nearly constant rate throughout the year. The storage fields also enable us to periodically increase the volume of natural gas that we can deliver by more than 40% above the volume that we could deliver solely from our production in the Appalachian region. The pipeline systems and storage fields are fully integrated with our operations.

In addition, we own and operate two brine treatment plants that process and treat waste fluid generated during the drilling, completion and production of oil and gas wells. The first plant, near Franklin, Pennsylvania, began operating in 1985. It provides services primarily to other oil and gas producers in southwestern New York, eastern Ohio and western Pennsylvania. In April 1998, we acquired a second brine treatment plant in Indiana, Pennsylvania that had been in existence since 1987.

Appalachian Region Marketing

The principal markets for our Appalachian region natural gas are in the northeastern United States. Cabot Oil & Gas Marketing purchases our natural gas production in the Appalachian region as well as production from local third-party producers and other suppliers to aggregate larger volumes of natural gas for resale. This marketing subsidiary sells natural gas to industrial customers, local distribution companies and gas marketers both on and off our pipeline and gathering system.

Approximately 65% of our natural gas sales volume in the Appalachian region is sold at index-based prices under contracts with a term of one to two years. In addition, spot market sales are made under month-to-month contracts, while industrial and utility sales generally are made under year-to-year contracts. Approximately 5% of Appalachian production is sold on fixed price contracts that typically renew annually. From time to time, we may also use financial hedges on a portion of our production to reduce the potential risk of falling prices when we believe market conditions are favorable.

Our Appalachian natural gas production has historically sold at a higher realized price, or premium, compared to production from other producing regions due to its proximity to northeastern markets. While year-to-year fluctuations in that premium are normal due to changes in market conditions, throughout the 1990's this

premium has typically been in the range of $0.40 to $0.50 per Mmbtu above the Henry Hub index spot price as published by Inside FERC's Gas Market Report for gas delivered to this point. This index is the basis for sales price in our standard natural gas sales contract. In 1999, however, the average premium declined to $0.27 per Mmbtu due to increases in supply in the eastern market. This decline continued into early 2000. However, late in 2000 and into 2001, the premium began to increase again due to strengthening of demand and perceived market shortages. The average 2001 premium was approximately $0.34 per Mmbtu. Due to this continued volatility, we are not able to predict the level of this premium for the future.

RISK MANAGEMENT

From time to time, when we believe that market conditions are favorable, we use certain financial instruments called derivatives to manage price risks associated with our production and brokering activities. While there are many different types of derivatives available, in 2001 we primarily employed natural gas and oil price swap and costless collar agreements to attempt to manage price risk more effectively. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas for the period is greater or less than the fixed price established for that period when the swap is put in place. The costless collar arrangements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor.

In December 2000, we entered into certain costless collar arrangements on half of our natural gas production for the months of February through October 2001. We realized revenue of $34.6 million under these arrangements. In December 2001, we again entered into price collar arrangements for 60% of our anticipated natural gas production for the months of January through April 2002. We will continue to evaluate the benefit of employing derivatives in the future. Please read Management's Discussion and Analysis of Financial Condition and Results of Operations - Commodity Price Swaps and Options for further discussion concerning our use of derivatives.

RESERVES

Current Reserves

The following table presents our estimated proved reserves at December 31, 2001.

	Natural Gas (Mmcf)			Liquids/(1)/ (Mbbl)			Tota
	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed
Gulf Coast	148,692	53,734	202,426	12,567	3,744	16,311	224,096
Rocky Mountains	167,067	47,717	214,784	1,618	482	2,100	176,774
Mid-Continent	166,198	27,236	193,434	817	130	947	171,098
Appalachia	322,689	102,671	425,360	326	--	326	324,644
Total	804,646	231,358	1,036,004	15,328	4,356	19,684	896,612

/(1)/ Liquids include crude oil, condensate and natural gas liquids (Ngl).

/(2)/ Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil, condensate or natural gas liquids.

The proved reserve estimates presented here were prepared by our petroleum engineering staff and reviewed by Miller and Lents, Ltd., independent petroleum engineers. For additional information regarding estimates of proved reserves, the review of such estimates by Miller and Lents, Ltd., and other information about our oil and gas reserves, see the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8. A copy of the review letter by Miller and Lents, Ltd. has been filed as an exhibit to this Form 10-K. Our estimates of proved reserves in the table above are consistent with those filed by us with other federal agencies. Our reserves are sensitive to natural gas and crude oil sales prices and their effect on economic producing rates. Our reserves are based on oil and gas index prices in effect on the last day of December 2001.

There are a number of uncertainties inherent in estimating quantities of proved reserves, including many

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factors beyond our control such as commodity pricing. Therefore, the reserve information in this Form 10-K represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that can not be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. In general, the volume of production from oil and gas properties declines as reserves are depleted. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced.

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Historical Reserves

The following table presents our estimated proved reserves for the periods indicated.

	Natural Gas (Mmcf)	Oil & Liquids (Mbbl)
December 31, 1998	996,756	7,677
Revision of Prior Estimates	(1,555)	128
Extensions, Discoveries and Other Additions	52,781	1,292
Production	(65,502)	(963)
Purchases of Reserves in Place	26,515	361
Sales of Reserves in Place	(79,393)	(306)
December 31, 1999	929,602	8,189
Revision of Prior Estimates	(14,796)	562
Extensions, Discoveries and Other Additions	103,600	2,032
Production	(60,934)	(988)

Purchases of Reserves in Place	5,118	120
Sales of Reserves in Place	(3,368)	(1)
December 31, 2000	959,222	9,914
Revision of Prior Estimates	(44,266)	254
Extensions, Discoveries and Other Additions	99,911	2,257
Production	(69,162)	(1,996)
Purchases of Reserves in Place	91,290	9,255
Sales of Reserves in Place	(991)	--
December 31, 2001	1,036,004	19,684
Proved Developed Reserves		
December 31, 1998	788,390	5,822
December 31, 1999	720,670	5,546
December 31, 2000	754,962	8,438
December 31, 2001	804,646	15,328

/(1)/ Includes natural gas and natural gas equivalents determined by using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil, condensate or natural gas liquids.

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Volumes and Prices; Production Costs

The following table presents regional historical information about our net wellhead sales volume for natural gas and oil (including condensate and natural gas liquids), produced natural gas and oil sales prices, and production costs per equivalent.

	Year Ended December 31, 2001	2000	1999
Net Wellhead Sales Volume			
Natural Gas (Bcf)			
Gulf Coast	25.6	14.1	15.5
West	26.2	29.0	29.3
Appalachia	17.4	17.8	20.7
Crude/Condensate/Ngl (Mbbl)			
Gulf Coast	1,694	669	579
West	267	289	341
Appalachia	35	32	43
Produced Natural Gas Sales Price ($/Mcf)/(1)/			
Gulf Coast	$ 4.44	$ 3.79	$ 2.29
West	3.88	2.86	1.96
Appalachia	4.96	3.24	2.53
Weighted Average	4.36	3.19	2.22
Crude/Condensate Sales Price ($/Bbl)/(1)/	$24.91	$26.81	$17.22

Production Costs ($/Mcfe)/(2)/	$ 0.72	$ 0.70	$ 0.59

/(1)/ Represents the average sales prices (net of hedge activity) for all production volumes (including royalty volumes) sold by Cabot Oil & Gas during the periods shown net of related costs (principally purchased gas royalty, transportation and storage).
/(2)/ Production costs include direct lifting costs (labor, repairs and maintenance, materials and supplies), and the costs of administration of production offices, insurance and property and severance taxes, but is exclusive of depreciation and depletion applicable to capitalized lease acquisition, exploration and development expenditures.

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Acreage

The following tables summarize our gross and net developed and undeveloped leasehold and mineral acreage at December 31, 2001. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

Leasehold Acreage

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
State						
Alabama	1,976	374	--	--	1,976	374
Colorado	14,263	13,359	190,529	92,799	204,792	106,158
Kansas	29,067	27,765	--	--	29,067	27,765
Kentucky	2,266	901	--	--	2,266	901
Louisiana	53,408	41,468	24,314	12,983	77,722	54,451
Michigan	739	205	6,823	6,773	7,562	6,978
Montana	397	210	44,288	33,552	44,685	33,762
New York	2,956	1,117	436	155	3,392	1,272
New Mexico	480	96	--	--	480	96
North Dakota	--	--	870	96	870	96
Ohio	6,288	2,389	9,225	7,361	15,513	9,750
Oklahoma	161,665	111,923	6,642	3,489	168,307	115,412
Pennsylvania	128,862	78,772	40,916	36,908	169,778	115,680
Texas	153,385	88,781	69,974	32,002	223,359	120,783
Utah	1,740	530	129,044	88,125	130,784	88,655
Virginia	22,195	20,072	7,606	4,981	29,801	25,053
West Virginia	577,372	542,752	170,168	113,241	747,540	655,993
Wyoming	141,733	70,959	197,622	128,912	339,355	199,871
Total	1,298,792	1,001,673	898,457	561,377	2,197,249	1,563,050

Mineral Fee Acreage

	Developed	Undeveloped	Total

	Gross	Net	Gross	Net	Gross	Net
State						
Colorado	--	--	160	6	160	6
Kansas	160	128	--	--	160	128
Louisiana	628	276	--	--	628	276
Montana	--	--	589	75	589	75
New York	--	--	4,281	1,070	4,281	1,070
Oklahoma	16,580	13,979	400	76	16,980	14,055
Pennsylvania	86	86	2,367	1,296	2,453	1,382
Texas	27	27	652	326	679	353
Virginia	17,817	17,817	100	34	17,917	17,851
West Virginia	97,455	79,093	50,458	49,497	147,913	128,590
Total	132,753	111,406	59,007	52,380	191,760	163,786
Aggregate Total	1,431,545	1,113,079	957,464	613,757	2,389,009	1,726,836

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Total Net Acreage by Region of Operation

	Developed	Undeveloped	Total
Gulf Coast	103,836	44,008	147,844
West	266,039	348,433	614,472
Appalachia	743,204	221,316	964,520
Total	1,113,079	613,757	1,726,836

Well Summary

The following table presents our ownership at December 31, 2001, in natural gas and oil wells in the Gulf Coast region (consisting of various fields located in Louisiana and Texas), in the Western region (consisting of various fields located in Oklahoma, Kansas, Colorado and Wyoming) and in the Appalachian region (consisting of various fields located in West Virginia, Pennsylvania, Virginia and Ohio). This summary includes natural gas and oil wells in which we have a working interest or a reversionary interest as in the case of certain Section 29 tight sands and Devonian shale wells.

	Natural Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	613	375.6	400	237.6	1,013	613.2
West	1,152	652.4	71	38.3	1,223	690.7
Appalachia	2,339	2,180.0	23	10.9	2,362	2,190.9
Total	4,104	3,208.0	494	286.8	4,598	3,494.8

Drilling Activity

We drilled wells, participated in the drilling of wells, or acquired wells as indicated in the regional tables below.

	Year Ended December 31, 2001 Gross	2001 Net	2000 Gross	2000 Net	1999 Gross	1999 Net
Gulf Coast						
Development Wells						
Successful	18	7.0	14	6.3	10	6.2
Dry	1	0.6	3	1.7	3	3.0
Extension Wells						
Successful	1	0.1	--	--	--	--
Dry	--	--	--	--	--	--
Exploratory Wells						
Successful	8	4.6	4	2.2	2	0.6
Dry	7	2.4	2	1.0	1	0.5
Total	35	14.7	23	11.2	16	10.3
Wells Acquired/(1)/	600	334.0	1	0.6	2	0.6
Wells in Progress at End of Period	5	3.6	2	1.1	1	0.3

	Year Ended December 31, 2001 Gross	2001 Net	2000 Gross	2000 Net	1999 Gross	1999 Net
West						
Development Wells						
Successful	43	24.9	33	22.7	19	9.0
Dry	3	1.5	3	1.0	1	1.0
Extension Wells						
Successful	5	2.4	7	3.9	1	0.3
Dry	--	--	--	--	--	--
Exploratory Wells						
Successful	1	0.8	1	0.3	--	--
Dry	4	3.0	1	0.5	2	1.3
Total	56	32.6	45	28.4	23	11.6
Wells Acquired/(1)/	10	0.1	1	0.4	27	10.7
Wells in Progress at End of Period	--	--	4	2.7	5	2.3

	Year Ended December 31, 2001 Gross	2001 Net	2000 Gross	2000 Net	1999 Gross	1999 Net
Appalachia						
Development Wells						
Successful	102	93.0	47	41.5	26	19.0

Dry	5	4.0	5	4.2	1	0.5
Extension Wells						
Successful	--	--	--	--	--	--
Dry	--	--	--	--	--	--
Exploratory Wells						
Successful	3	3.0	5	3.8	3	2.0
Dry	7	6.3	4	2.5	4	2.0
Total	117	106.3	61	52.0	34	23.5
Wells Acquired/(1)/	19	19.0	--	--	--	--
Wells in Progress at End of Period	--	--	3	3.0	1	0.3

/(1)/ Includes the acquisition of net interest in certain wells in which we already held an ownership interest. Does not include certain interests in Section 29 tight sands and Devonian shale wells purchased and then resold during 1999.

Competition

Competition in our primary producing areas is intense. Price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery records, affect competition. We believe that our extensive acreage position, existing natural gas gathering and pipeline systems and storage fields enhance our competitive position over other producers in the Appalachian region who do not have similar systems or facilities in place. We also believe that our competitive position in the Appalachian region is enhanced by the lack of significant competition from major oil and gas companies. We also actively compete against other companies with substantially larger financial and other resources, particularly in the Western and Gulf Coast regions.

OTHER BUSINESS MATTERS

Major Customer

We had no sales to any customer that exceeded 10% of our total gross revenues in 2001, 2000 or 1999.

Seasonality

Demand for natural gas has historically been seasonal, with peak demand and typically higher prices occurring during the colder winter months.

Regulation of Oil and Natural Gas Exploration and Production

Exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits to drill wells, maintaining bonding requirements to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells which may be drilled in a given field, and the unitization or pooling of oil and natural gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibiting the venting or flaring of natural gas, and imposing certain requirements regarding the ratability of production. The effect of these regulations is to limit the amounts of oil and natural gas we can produce from our wells, and to limit the number of wells or the locations where we can drill. Because these statutes, rules and regulations undergo constant review and often are amended, expanded and reinterpreted, we are unable to predict the future cost or impact of regulatory compliance. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. We do not believe, however, we are affected materially differently by these regulations than others in the industry.

Natural Gas Marketing, Gathering and Transportation

Federal legislation and regulatory controls have historically affected the price of the natural gas produced and the manner in which such production is transported and marketed. Under the Natural Gas Act of 1938, the FERC regulates the interstate sale and transportation of natural gas for resale. The FERC's jurisdiction over interstate natural gas sales was substantially modified by the Natural Gas Policy Act of 1978 (NGPA), under which the FERC continued to regulate the maximum selling prices of certain categories of gas sold in "first sales" in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (Decontrol Act) deregulated natural gas prices for all "first sales" of natural gas, including all sales of our own production. As a result, all of our produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. The FERC's jurisdiction over natural gas transportation and the sale for resale of natural gas in interstate commerce was not affected by the Decontrol Act.

Natural gas sales are affected by intrastate and interstate gas transportation regulation. Beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992, the FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes were intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of gas to the primary role of gas transporters. Order No. 636 required that interstate pipelines generally cease making sales of natural gas. At the same time, FERC retained its statutory jurisdiction over the sale for resale of natural gas in interstate commerce, but issued to all entities (except interstate pipelines) a blanket certificate to make sales for resale of natural gas in interstate commerce at market based prices. As a result, pipelines divested their gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants. Interstate pipelines are now required to provide open and nondiscriminatory transportation and transportation-related services to all producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking service. The FERC expanded the impact of open access

regulations to intrastate commerce through its implementation of the NGPA provisions allowing intrastate pipelines to provide service in intrastate commerce on behalf of interstate pipelines.

More recently, the FERC has pursued other policy initiatives that have affected natural gas marketing. Most notable are (1) the large-scale divestiture of interstate pipeline-owned gas gathering facilities to affiliated or non-affiliated companies, which is a result of the FERC's requirement in Order No. 636 that interstate pipelines unbundle gathering services from transportation services, (2) further development of rules governing the relationship of the pipelines with their marketing affiliates, (3) the publication of standards relating to the use of electronic bulletin boards and electronic data exchange by the pipelines to make available transportation information on a timely basis and to enable transactions to occur on a purely electronic basis, and (4) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services upon a showing of lack of market control in the relevant service market.

The FERC continued its efforts to develop a competitive natural gas market with Order No. 637, issued in 2000. Order No. 637 modifies FERC regulations to: (1) lift the cost-based cap on pipeline transportation rates in the capacity release market until September 30, 2002, for releases of pipeline capacity for periods less than one year; (2) permit pipelines to file for authority to charge different maximum cost-based rates for peak and off-peak periods; (3) encourage auctions for pipeline capacity; (4) require that pipelines implement imbalance management services for shippers; (5) restrict the ability of pipelines to impose penalties for imbalances, overruns, and non-compliance with operational flow orders; and (6) implement a number of new pipeline reporting requirements to enhance market transparency. These Order No. 637 requirements are being implemented by pipelines through individual tariff reform filings. Order No. 637 also requires the FERC Staff to analyze whether the FERC should develop additional fundamental policy changes, including whether to pursue performance-based or other non-cost based ratemaking methods and whether the FERC should mandate greater standardization in terms and conditions of service across the interstate pipeline grid.

As a result of these changes, sellers and buyers of gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace.

We can not predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. Similarly, it is impossible to predict what proposals, if any, that affect the oil and natural gas_industry might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas, can not be predicted.

Our pipeline systems and storage fields in West Virginia are regulated for safety compliance by the U.S. Department of Transportation and the West Virginia Public Service Commission.

Federal Regulation of Petroleum

Our sales of oil and natural gas liquids are not regulated and are at market prices. The price received from the sale of these products is affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines. Effective January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. These regulations have generally been approved on judicial review. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. The first such review has been completed and on December 14, 2000, the FERC reaffirmed the current index. We are not able to predict with certainty the effect upon us of these relatively new federal regulations or of the periodic

review by the FERC of the index.

Environmental Regulations

General. Our operations are subject to extensive federal, state and local laws and regulations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Permits are required for the operation of our various facilities. These permits can be revoked, modified or renewed by issuing authorities. Governmental authorities enforce compliance with their regulations through fines, injunctions or both. Government regulations can increase the cost of planning, designing, installing and operating oil and gas facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities related to environmental compliance issues are part of oil and gas production operations. No assurance can be given that significant costs and liabilities will not be incurred. Also, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production could result in substantial costs and liabilities to us.

Solid and Hazardous Waste. We currently own or lease, and have in the past owned or leased, numerous properties that were used for the production of oil and gas for many years. Although operating and disposal practices that were standard in the industry at the time may have been utilized, it is possible that hydrocarbons or other solid wastes may have been disposed of or released on or under the properties currently owned or leased by us. State and federal laws applicable to oil and gas wastes and properties have become more strict over time. Under these increasingly stringent requirements, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners and operators) or clean up property contamination (including groundwater contamination by prior owners or operators) or to perform plugging operations to prevent future contamination.

We generate some hazardous wastes that are already subject to the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The Environmental Protection Agency (EPA) has limited the disposal options for certain hazardous wastes. It is possible that certain wastes currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes under RCRA or other applicable statutes. We could, therefore, be subject to more rigorous and costly disposal requirements in the future than we encounter today.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release of hazardous substances into the environment. These persons include the owner and operator of a site and any party that disposed of or arranged for the disposal of hazardous substances found at a site. CERCLA also authorizes the EPA, and in some cases, private parties, to undertake actions to clean up such hazardous substances, or to recover the costs of such actions from the responsible parties. In the course of business, we have generated and will continue to generate wastes that may fall within CERCLA's definition of hazardous substances. We may also be an owner or operator of sites on which hazardous substances have been released. As a result, we may be responsible under CERCLA for all or part of the costs to clean up sites where such wastes have been disposed. See Item 3 Legal Proceedings for a discussion of the Casmalia Superfund Site.

Oil Pollution Act. The federal Oil Pollution Act of 1990 (OPA) and resulting regulations impose a variety of obligations on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. The term "waters of the United States" has been broadly defined to include inland water bodies, including wetlands and intermittent streams. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages.

Clean Water Act. The Federal Water Pollution Control Act (FWPCA or Clean Water Act) and resulting regulations, which are implemented through a system of permits, also govern the discharge of certain contaminants into waters of the United States. Sanctions for failure to comply strictly with the Clean Water Act are generally resolved by payment of fines and correction of any identified deficiencies. However, regulatory agencies could require us to cease construction or operation of certain facilities that are the source of water discharges. We believe that we comply with the Clean Water Act and related federal and state regulations in all material respects.

Clean Air Act. Our operations are subject to local, state and federal laws and regulations to control emissions from sources of air pollution. Payment of fines and correction of any identified deficiencies generally resolve penalties for failure to comply strictly with air regulations or permits. Regulatory agencies could also require us to cease construction or operation of certain facilities that are air emission sources. We believe that we substantially comply with the emission standards under local, state, and federal laws and regulations.

Employees

As of December 31, 2001, Cabot Oil & Gas had 366 active employees. We recognize that our success is significantly influenced by the relationship we maintain with our employees. Overall, we believe that our relations with our employees are satisfactory. The Company and its employees are not represented by a collective bargaining agreement.

Other

Our profitability depends on certain factors that are beyond our control, such as natural gas and crude oil prices. Please see Items 7 and 7A. We face a variety of hazards and risks that could cause substantial financial losses. Our business involves a variety of operating risks, including blowouts, cratering, explosions and fires, mechanical problems, uncontrolled flows of oil, natural gas or well fluids, formations with abnormal pressures, pollution and other environmental risks, and natural disasters. We conduct operations in shallow offshore areas, which are subject to additional hazards of marine operations, such as capsizing, collision and damage from severe weather.

Our operation of natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures. Any of these events could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites, could increase these risks. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations. The costs of these insurance policies are somewhat dependent on our historical claims experience and also the areas in which we choose to operate. During the past few years, we have drilled a higher percentage of our wells in the Gulf Coast, where insurance rates are significantly higher than in other regions such as Appalachia. At December 31, 2001, we owned or operated approximately 2,900 miles of natural gas gathering and transmission pipeline systems throughout the United States. As part of our normal maintenance program, we have identified certain segments of our pipelines that we believe may require repair, replacement or additional maintenance and we schedule this maintenance as appropriate.

The sale of our oil and gas production depends on a number of factors beyond our control. The factors include the availability and capacity of transportation and processing facilities. Our failure to access these facilities and obtain these services on acceptable terms could materially harm our business.

ITEM 2. PROPERTIES

See Item 1. Business.

ITEM 3. LEGAL PROCEEDINGS

We are a party to various legal proceedings arising in the normal course of our business. All known liabilities are fully accrued based on management's best estimate of the potential loss. In management's opinion, final judgments or settlements, if any, which may be awarded in connection with any one or more of these suits and claims would not have a significant impact on the results of operations, financial position or cash flows of any period.

Environmental Liability

The EPA notified us in February 2000 of our potential liability for waste material disposed of at the Casmalia Superfund Site ("Site"), located on a 252-acre parcel in Santa Barbara County, California. Over 10,000 separate parties disposed of waste at the Site while it was operational from 1973 to 1992. The EPA stated that federal, state and local governmental agencies along with the numerous private entities that used the Site for disposal of approximately 4.5 billion pounds of waste would be expected to pay the clean-up costs, which are estimated by the EPA to be $271.9 million. The EPA is also pursuing the owners/operators of the Site to pay for remediation.

Documents received by us with the notification from the EPA indicate that we used the Site principally to dispose of salt water from two wells over a period from 1976 to 1979. There is no allegation that we violated any laws in the disposal of material at the Site. The EPA's actions stem from the fact that the owners/operators of the Site do not have the financial means to implement a closure plan for the Site.

A group of potentially responsible parties, including us, formed a group called the Casmalia Negotiating Committee ("CNC"). The CNC has had extensive settlement discussions with the EPA and has reached a settlement in principal to pay approximately $27 million toward Site clean up in return for a release from liability. The CNC is currently negotiating a consent decree to memorialize the settlement. On January 30, 2002, we placed $1,283,283 in an escrow account. This amount approximates our volumetric share of EPA's cost estimate, plus a 5% premium and is our settlement amount. The escrow account is being funded by us and many other CNC members to maximize the likelihood that there will be sufficient funds to fund the settlement agreement upon its completion, which is expected later in 2002. This cash settlement, once released from escrow and paid to the federal government, will resolve all federal claims against us for response costs and will release us from all response costs related to the Site, except for future claims against us for natural resource damage, unknown conditions, transshipment risks and claims by third parties, all of which are expected to be covered by insurance to be purchased by participating CNC members. Responsibility for certain State of California oversight and response costs, while not covered by the settlement or insurance, are not expected to be material. No determination has been made as to whether any insurance arrangement will allow us to recover our contribution to the settlement.

We have established a reserve that management believes to be adequate to provide for this environmental liability based on its estimate of the probable outcome of this matter and estimated legal costs.

Wyoming Royalty Litigation

In June 2000, two overriding royalty owners sued us in Wyoming State court for unspecified damages. The plaintiffs have requested class certification under the Wyoming Rules of Civil Procedure and allege that we have deducted improper costs of production from royalty payments to the plaintiffs and other similarly situated persons. Additionally, the suit claims that we have failed to properly inform the plaintiffs and other similarly situated persons of the deductions taken from royalties. In December 2001, fourteen overriding royalty owners sued us in Wyoming federal court. The plaintiffs in the federal case have made the same general claims pertaining to deductions from their overriding royalty as the plaintiffs in the Wyoming state court case but have not asked for class certification.

Management believes that we have substantial defenses to these claims and intends to vigorously assert such defenses. We have a reserve that we believe is adequate to provide for these potential liabilities based on our estimate of the probable outcome of this matter. While the potential impact to us may materially affect quarterly or annual financial results including cash flows, management does not believe it would materially impact our financial position or results of operations.

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West Virginia Royalty Litigation

In late December 2001, two royalty owners sued us in West Virginia State court for an unspecified amount of damages. The plaintiffs have requested class certification under the West Virginia Rules of Civil Procedure and allege that we have failed to pay royalty based upon the wholesale market value of the gas produced, that we have taken improper deductions from the royalty and that we have failed to properly inform the plaintiffs and other similarly situated persons of deductions taken from the royalty.

Although the investigation into this claim has just begun, we intend to vigorously defend the case. We cannot currently determine the likelihood or range of any potential outcome.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the period from October 1, 2001 to December 31, 2001.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information about our executive officers as of February 15, 2002, as such term is defined in Rule 3b-7 of the Securities Exchange Act of 1934, and certain of our other officers.

Name	Age	Position	Office
Ray R. Seegmiller	66	Chairman of the Board and Chief Executive Officer	
Dan O. Dinges	48	President and Chief Operating Officer	
Michael B. Walen	53	Senior Vice President, Exploration and Production	
J. Scott Arnold	48	Vice President, Land and Associate General Counsel	
R. Scott Butler	47	Vice President, Regional Manager, Western Region	
Robert G. Drake	54	Vice President, Management Information Systems	
Abraham D. Garza	55	Vice President, Human Resources	
Jeffrey W. Hutton	46	Vice President, Marketing	
Lisa A. Machesney	46	Vice President, Managing Counsel and Corporate Secretary	
A. F. (Tony) Pelletier	49	Vice President, Regional Manager, Gulf Coast Region	
Scott C. Schroeder	39	Vice President, Chief Financial Officer and Treasurer	
Henry C. Smyth	55	Vice President and Controller	

All officers are elected annually by our Board of Directors. Except for the following, all of the executive officers have been employed by Cabot Oil & Gas Corporation for at least the last five years.

Dan O. Dinges joined Cabot Oil & Gas Corporation as President and Chief Operating Officer and as a member of the Board of Directors in September 2001. Mr. Dinges came to Cabot after a 20-year career with Samedan Oil Corporation, a subsidiary of Noble Affiliates, Inc. The last three years, Mr. Dinges served as Samedan's Senior Vice President, as well as Division General Manager for the Offshore Division, a position he held since August 1996. He also served as a member of the Executive Operating Committee for Samedan. Mr. Dinges started his career as a Landman for Mobil Oil Corporation covering Louisiana, Arkansas and the central Gulf of Mexico. After four years of expanding responsibilities at Mobil he joined Samedan as a Division Landman - Offshore. Over the years, Mr. Dinges held positions of increasing responsibility at Samedan including Division Manager, Vice President and ultimately Senior Vice President. Mr. Dinges received his BBA degree in Petroleum Land Management from The University of Texas.

R. Scott Butler has been Vice President, Regional Manager, Western Region since October 2001. Mr. Butler joined Cabot in 1998 as Director of Exploration and was named Regional Manager, Western Region, in February 2001. He came to Cabot following a 19-year career with Chevron where he served in roles of increasing responsibility focusing on exploration in the lower 48 states. Mr. Butler holds a bachelor's degree from Stanford University and a master's from the University of Nevada at Reno, both in geology. He is a member of the American Association of Petroleum Geologists and serves as a director-at-large for the Independent Petroleum Association of Mountain States.

A. F. (Tony) Pelletier has been Vice President, Regional Manager, Gulf Coast Region since October 2001. Mr. Pelletier joined the Company in April 2001 as Regional Manager, Gulf Coast. Before coming to Cabot, he held positions of increasing responsibility at PetroCorp Incorporated, most recently as Executive Vice President and Chief Operating Officer. Prior to that, he worked at Exxon Company USA in a variety of engineering and supervisory capacities. Mr. Pelletier holds a B.S. in Mechanical Engineering and a master's in Civil Engineering, both from Texas A&M University. He is a registered professional engineer in the state of Texas.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Common Stock is listed and principally traded on the New York Stock Exchange under the ticker symbol "COG." The following table presents the high and low closing sales prices per share of the Common Stock during certain periods, as reported in the consolidated transaction reporting system. Cash dividends paid per share of the Common Stock are also shown.

	High	Low	Cash Dividends
2001			
First Quarter	$32.00	$25.88	$0.04
Second Quarter	34.20	24.22	0.04
Third Quarter	26.33	16.70	0.04
Fourth Quarter	24.99	18.35	0.04
2000			
First Quarter	$18.06	$14.19	$0.04
Second Quarter	24.94	16.75	0.04
Third Quarter	21.25	17.38	0.04
Fourth Quarter	31.75	19.00	0.04

As of January 31, 2002, there were 849 registered holders of the Common Stock. Shareholders include individuals, brokers, nominees, custodians, trustees, and institutions such as banks, insurance companies and pension funds. Many of these hold large blocks of stock on behalf of other individuals or firms.

ITEM 6. SELECTED HISTORICAL FINANCIAL DATA

The following table summarizes selected consolidated financial data for Cabot Oil & Gas for the periods indicated. This information should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations, and the Consolidated Financial Statements and related Notes.

	Year Ended December 31,				
(In thousands, except per share amounts)	2001	2000	1999	1998	1997

Income Statement Data					
Operating Revenues	$ 447,042	$368,651	$294,037	$251,340	$269,771
Income from Operations	95,366	64,817	39,498	27,403	63,852
Net Income Available to Common Stockholders	47,084	29,221	5,117	1,902	23,231
Basic Earnings per Share Available to Common Stockholders/(1)/	$ 1.56	$ 1.07	$ 0.21	$ 0.08	$ 1.00
Dividends per Common Share	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Balance Sheet Data					
Properties and Equipment, Net	$ 981,338	$623,174	$590,301	$629,908	$469,399
Total Assets	1,069,031	735,634	659,480	704,160	541,805
Long-Term Debt	393,000	253,000	277,000	327,000	183,000
Stockholders' Equity	346,552	242,505	186,496	182,668	184,062

/(1)/See Earnings per Common Share under Note 15 of the Notes to the Consolidated Financial State

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our results of operations and our present financial condition. Our Consolidated Financial Statements and the accompanying notes included elsewhere in this Form 10-K contain additional information that should be referred to when reviewing this material.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed. Please read Forward-Looking Information on page 32.

We operate in one segment, natural gas and oil exploration and development.

OVERVIEW

Our financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas market has remained prevalent in the last few years. In the first quarter of 1999, we experienced a decline in energy commodity prices, resulting in lower revenues and net income during this period. However, in the summer of 1999 and continuing through 2000, prices improved. For the months of April through October 2000, we had certain natural gas hedges in place that prevented us from realizing the full impact of this price environment. (See the Commodity Price Swaps and Options discussion about hedging on page 38.) Despite this limitation, our realized natural gas price for each month in the year 2000 was higher than the same month of any previous year. In the final months of 2000 and into early 2001, the NYMEX futures market reported unprecedented natural gas contract prices. We benefited from this market with our realized natural gas price reaching $5.66 per Mcf in December and $8.46 per Mcf in January 2001. When the NYMEX futures market was near its high on the last day of December 2000, we entered into a series of price collars that protected us from the subsequent price decline until their expiration in October 2001.

These price collar arrangements boosted 2001 revenue by $34.6 million, increasing the average realized natural gas price by $0.50 per Mcf. The table below illustrates how natural gas prices have fluctuated over the course of 2001. "Index" represents the Henry Hub index price. The "2001" price is the natural gas price realized by us and it includes the impact of the natural gas price collar arrangements:

(in $ per Mcf) Natural Gas Prices by Month

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	9.91	6.22	5.03	5.35	4.87	3.73	3.16	3.19	2.34	1.86	3.16	2.28
2001	8.46	6.28	4.91	5.05	5.08	4.25	3.96	3.79	3.57	3.24	3.06	2.32

Prices for crude oil have followed a similar path as the commodity market fell through 2001. The table below contains the West Texas Intermediate index price ("Index") and our realized crude oil prices by month for 2001.

(in $ per Bbl) Crude Oil Prices by Month

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	28.66	27.40	26.30	28.46	28.37	26.26	26.35	27.20	23.43	21.18	19.44	19.84
2001	30.32	29.20	26.44	26.31	29.12	27.85	24.72	25.71	24.50	22.85	19.05	19.85

We reported earnings of $1.56 per share, or $47.1 million, for 2001. This is up from the $1.07 per share, or $29.2 million, reported in 2000. The improvement is a result of the stronger commodity price environment during the year 2001 and the impact of the natural gas price collar arrangements, which combined to push our realized natural gas price up 37% to $4.36 per Mcf. Additionally, natural gas production was up 14% and crude oil sales volumes were up 100% from last year. Overall, on a Mcf equivalent basis, our production grew more than 21% over 2000. A 12% production increase was a result of our drilling successes in 2000 and 2001, and the remaining 9% increase resulted from the acquisition of Cody Company, which was effective August 1, 2001.

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A discussion of our results from recurring operations can be found in the Results of Operations section, beginning on page 33. Before taking into account selected items, net income for 2001 was $51.9 million, or $1.71 per share, and $30.2 million, or $1.10 per share for 2000.

In August 2001, we acquired the stock of Cody Company, the parent of Cody Energy LLC ("Cody acquisition") for $231.2 million consisting of $181.3 million of cash and 1,999,993 shares of common stock valued at $49.9 million. Substantially all of the proved reserves of Cody Company are located in the onshore Gulf Coast region. The acquisition was recorded using the purchase method of accounting. As such, the Company reflected the assets and liabilities acquired at fair value in the Company's balance sheet effective August 1, 2001 and the results of operations of Cody Company beginning August 1, 2001. In 2001, these acquired properties contributed 6.2 Bcfe of production, $17.0 million of operating revenue and $19.2 million of operating expenses including $11.6 million of DD&A expense. Additional 2001 costs included $5.3 million of interest expense. These properties contributed $10.3 million in operating cash flow to 2001. The purchase price totaling approximately $315.6 million was allocated to specific assets and liabilities based on certain estimates of fair values, resulting in approximately $302.4 million allocated to property and $13.2 million allocated to working capital items. This $315.6 million was comprised of non-cash common stock consideration of $49.9 million and a non-cash deferred tax gross-up of $78.0 million and acquisition related fees and costs of $6.4

million. The deferred tax gross-up pertains to the deferred income taxes attributable to the differences between the tax basis and the estimated fair value of the acquired oil and gas properties.

We drilled 208 gross wells with a success rate of 87% in 2001 compared to 129 gross wells and an 86% success rate in 2000. Total capital expenditures were $453.4 million for 2001, including $181.3 million in cash and $49.9 million in common stock paid for Cody Company, compared to $122.6 million in 2000. Capital spent in drilling activity increased $39.5 million, with the largest activity increase coming in the Gulf Coast region, where we continued to develop the Etouffee, Augen and Lake Pelto prospects in south Louisiana and initiated new exploration in south Texas. We increased our spending for seismic data, both 2-D and 3-D, and lease acquisition costs both in the Gulf Coast and Rocky Mountains in order to evaluate and expand our drilling opportunities for 2001 and beyond. The largest portion of this spending occurred in December 2001.

Total equivalent production for 2001 was 81.1 Bcfe, an increase of 21% over 2000. Of this increase, 12% resulted from drilling activity and the remaining 9% was a result of the production from the acquired Cody Company properties.

At the end of 2001, our debt-to-total capitalization ratio was 53.1%, up slightly from the end of 2000. This result was achieved despite expending $181.3 million as cash consideration in the Cody acquisition which was sourced primarily by the issuance of $170 million in private placement Notes. During 2000, we improved our debt-to-total capitalization ratio from 61.1% at the end of 1999 to 52.6% at the close of 2000. This improvement was a result of several significant accomplishments. We sold 3.4 million shares of common stock in May 2000 for net proceeds of $71.5 million, of which $51.6 million was used to repurchase all of our preferred stock. The remaining proceeds, along with another $14.8 million from employee stock option exercises, were used to reduce debt and pay dividends. From year end 1999 to year end 2000, we reduced debt by $24 million.

We remain focused on our strategies to grow through the drill bit, concentrating on the highest expected_return opportunities, and from synergistic acquisitions. We believe these strategies are appropriate in the current industry environment, enabling us to add shareholder value over the long term.

The preceding paragraphs, discussing our strategic pursuits and goals, contain forward-looking information. Please read Forward-Looking Information on page 32.

FINANCIAL CONDITION

Capital Resources and Liquidity

Our capital resources consist primarily of cash flows from our oil and gas properties and asset-based borrowing supported by oil and gas reserves. Our level of earnings and cash flows depends on many factors, including the price of natural gas and oil, our ability to find and produce hydrocarbons and our ability to control and reduce costs. Demand for

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natural gas has historically been subject to seasonal influences characterized by peak demand and higher prices in the winter heating season. However, in the summer of 2000, our realized gas prices began to climb to unseasonably high levels and by January 2001, we realized the highest prices in the Company's history. Then in 2001, our realized natural gas price declined throughout the year to a low of $2.32 per Mcf in December. A mild winter and the economic recession may be contributing factors in the 2001 pricing volatility.

The primary sources of cash during 2001 were funds generated from operations, proceeds from the issuance of Notes (see Note 5 of the Notes to the Consolidated Financial Statements) and, to a lesser extent, proceeds from the sale of stock. Funds were used primarily for exploration and development expenditures, including the acquisition of Cody Company in August 2001, and dividend payments.

We had a net cash outflow of $1.9 million during 2001. The net cash inflow from operating activities of $250.4 million combined with the increase in debt of $124.0 million to substantially fund the $386.1 million of cash used for capital and exploration expenditures. Cash proceeds from the sales of non-strategic assets and the sale of stock combined to provide an additional $14.6 million of cash flow.

(In millions)	2001	2000	1999
Cash Flows Provided by Operating Activities	$250.4	$119.0	$92.5

Cash flows provided by operating activities in 2001 were $131.4 million higher than in 2000 and cash flows provided by operating activities in 2000 were $26.5 million higher than in 1999. These improvements were primarily a result of increased revenues from higher realized commodity prices and to a lesser extent to increased natural gas and oil production.

(In millions)	2001	2000	1999
Cash Flows Used by Investing Activities	$(379.2)	$(116.1)	$(37.4)

Cash flows used by investing activities in 2001 included the $181.3 million cash portion of the Cody Company acquisition. Additionally, capital spending for drilling and facilities increased $39.5 million, or 49%, from last year to $119.5 million. We drilled 208 gross wells, which represents a 61% increase over 2000.

Cash flows used by investing activities in 2000 were attributable to capital and exploration expenditures of $119.2 million, offset by the receipt of $3.1 million in proceeds received from the sale of non-strategic oil and gas properties.

Cash flows used by investing activities in 1999 were attributable to capital and exploration expenditures of $93.7 million, offset by the receipt of $56.3 million in proceeds received from the sale of non-strategic oil and gas properties.

(In millions)	2001	2000	1999
Cash Flows Provided (Used) by Financing Activities	$126.9	$3.0	$(55.6)

Cash flows provided by financing activities in 2001 included the impact of issuing $170 million in a private placement of Notes in July 2001 used to partially fund the Cody Company acquisition. Partially offsetting this debt increase was the reduction to the balance outstanding on the revolving credit facility and the May 2001 prepayment of $16 million in debt that was due in May 2002.

Cash flows provided by financing activities in 2000 included $85.1 million in proceeds received from the sale of common stock, both in a block trade and through the exercise of employee stock options. Of the proceeds, $51.6 million was used to repurchase all of the outstanding shares of preferred stock. Additional cash used in financing activities included $24 million used to reduce the year-end debt balance to $269 million from $293 million in 1999 and cash used to pay dividends to stockholders.

Cash flows used by financing activities in 1999 included $50 million used to reduce the year-end debt balance to $293 million from $343 million in 1998 and cash used to pay cash dividends to stockholders.

We have a revolving credit facility with a group of banks, the revolving term of which runs to December 2003. The available credit line under this facility, currently $250 million, is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the banks' petroleum engineer) and other assets. Accordingly, oil and gas prices are an important part of this computation. Since the current price environment remains volatile, management can not predict how future price levels may change the banks' long-term price outlook. To reduce the impact of any redetermination, we strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. At year end, this excess capacity totaled $127 million, or 51% of the total available credit line. Management believes it has the ability to finance, if necessary, our capital requirements, including acquisitions. Oil and gas prices also affect the calculation of the financial ratios for debt covenant compliance. Please read Note 5 of the Notes to the Consolidated Financial Statements for a more detailed discussion of our revolving credit facility.

In the event that the available credit line is adjusted below the outstanding level of borrowings, we have a period of 180 days to reduce our outstanding debt to the adjusted credit line. The revolving credit agreement also includes a requirement to pay down half of the debt in excess of the adjusted credit line within the first 90 days of any adjustment.

Our 2002 interest expense is expected to be approximately $29.2 million, including interest on the $170 million 7.33% weighted average fixed rate notes used to partially fund the acquisition of Cody Company. In May 2001, a $16 million principal payment was made on the 10.18% Notes. This amount had been reflected as "Current Portion of Long-Term Debt" on the balance sheet. Additionally, the final $16 million payment on these notes that was due in May 2002 was paid in May 2001 using existing capacity on the revolving credit agreement.

Capitalization

Our capitalization information is as follows:

(In millions)	As of December 31, 2001	2000	1999
Long-Term Debt	$393.0	$253.0	$277.0
Current Portion of Long-Term Debt	--	16.0	16.0
Total Debt	$393.0	$269.0	$293.0
Stockholders' Equity			
Common Stock (net of Treasury Stock)	$346.6	$242.5	$129.8
Preferred Stock	--	--	56.7
Total Equity	346.6	242.5	186.5

Total Capitalization	$739.6	$511.5	$479.5
Debt to Capitalization	53.1%	52.6%	61.1%

During 2001, dividends were paid on our common stock totaling $4.8 million. We have paid quarterly common stock dividends of $0.04 per share since becoming publicly traded in 1990. The amount of future dividends is determined by our Board of Directors and is dependent upon a number of factors, including future earnings, financial condition and capital requirements.

In May 2000, we bought back all of the shares of preferred stock from the holder for $51.6 million. Since this stock had been recorded at a stated value of $56.7 million on our balance sheet, we realized a negative dividend to preferred stockholders of $5.1 million. We received net proceeds of $71.5 million from the sale of 3.4 million shares of common stock in a public offering primarily to fund this transaction. After repurchasing the preferred stock, the excess proceeds were used to reduce debt.

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Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital and exploration activities, excluding major oil and gas property acquisitions, with cash generated from operations. We budget these capital expenditures based on our projected cash flows for the year.

The following table presents major components of our capital and exploration expenditures for the three years ended December 31, 2001.

(In millions)	2001	2000	1999
Capital Expenditures			
Drilling and Facilities	$119.5	$ 80.0	$43.9
Leasehold Acquisitions	12.9	10.9	7.2
Pipeline and Gathering	3.8	3.2	3.8
Other	1.9	2.6	3.3
	138.1	96.7	58.2
Proved Property Acquisitions	244.1/(1)/	6.0	18.4
Exploration Expenses	71.2	19.9	11.5
Total	$453.4	$122.6	$88.1

/(1)/ The 2001 amount includes the $49.9 million common stock component of the Cody acquisition and excludes the $78.0 million deferred tax gross-up. See Note 14, Cody Acquisition.

Total capital and exploration expenditures for 2001 increased $330.8 million compared to 2000, primarily as a result of the $231.2 million Cody acquisition. The remaining increase of $99.6 million was due primarily to increased drilling activity as well as increases in leasehold acquisitions costs consistent with our future drilling plans. The 2001 drilling program included an over 68% increase in net wells drilled and a $15.3 million increase in geological and geophysical expenses, including costs of obtaining seismic data that supports future drilling programs.

We plan to drill 121 gross wells in 2002 compared with 208 gross wells drilled in 2001. This 2002 drilling program includes $104.6 million in total capital and exploration expenditures, down from $453.4 million in 2001, which was our largest capital program to date. Expected spending in 2002 includes $62.6 million for drilling and dry hole exposure, $7.8 million for lease acquisition and $9.9 million in geological and geophysical expenses. In addition to the drilling and exploration program, other 2002 capital expenditures are planned primarily for production equipment and for gathering and pipeline infrastructure maintenance and construction. We will continue to assess the natural gas price environment and may increase or decrease the capital and exploration expenditures accordingly.

Contractual Obligations

We are committed to making cash payments in the future on two types on contracts: Note agreements and leases. We have no off-balance sheet debt or other such unrecorded obligations and we have not guaranteed the debt of any other party. Below is a schedule of the future payments that we were obligated to make based on agreements in place as of December 31, 2001.

	Payments Due by Year			
(in thousands)	Total	2002	2003 to 2004	200 to 2
Long-Term Debt /(1)/	$393,000	$ --	$123,000	$40,
Operating Leases /(2)/	29,843	5,194	8,555	7,
Total Contractual Cash Obligations	$422,843	$5,194	$131,555	$47,

/(1)/ The $123 million shown as scheduled for payment in 2003 represents the December 31, 2001 balance outstanding on the revolving credit facility. Typically, we are able to replace this credit agreement with a new one as this comes due. See discussion in Note 5 of the Notes to the Consolidated Financial Statements.

/(2)/ A discussion of operating leases can be found in Note 8 of the Notes to the Consolidated Financial Statements. We have no capital leases.

Potential Impact of Our Critical Accounting Policies

Readers of this document and users of the information contained in it should be aware of how certain events may impact our financial results based on the accounting policies in place. The three most significant policies are discussed below.

Commodity Pricing and Risk Management Activities

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and, to a lesser extent, oil. Declines in oil and gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil and gas prices also may reduce the amount of oil and gas that we can produce economically. Historically, oil and gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results. In particular, substantially lower prices would significantly reduce revenue and could potentially impact the outcome of our annual impairment test under SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" when adopted. Because our reserves are predominantly natural gas, changes in natural gas prices may have a particularly large impact on our financial results.

The majority of production is sold at market responsive prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. However, management may mitigate this price risk in a number of ways. Most recently, we have used financial instruments such as natural gas price collar arrangements to reduce the impact of declining pricing on our revenue. Under a price collar arrangement, there is also risk that the index prices will rise above the ceiling price and the Company will not be able to realize the full benefit of the market improvement.

We covered 16% of our production in 2000 with natural gas price collar arrangements and prices rose above the ceiling during some months. If we had not had these collars in place in 2000, our realized natural gas price would have been $0.17 per Mcf higher. In 2001, we covered 35% of our natural gas production with price collar arrangements and prices were below the floor for several months. The gains from the 2001 price collars improved our annual realized natural gas price by $0.50 per Mcf.

Successful Efforts Method of Accounting

We use the successful efforts method of accounting for oil and gas producing activities. Under this method, acquisition costs for proved and unproved properties are capitalized when incurred. Exploration costs, including seismic purchases and processing, exploratory dry hole drilling costs and costs of carrying and retaining unproved properties are expensed as incurred. During 2001, we drilled 30 exploratory wells and 18 of them were unsuccessful, adding $37.9 million to exploration expense. This 40% success rate for exploratory wells is not unusual, and as we focus more on our exploration program, we are exposed to the risk of dry hole expense. Development costs, including the costs to drill and equip development wells, and successful exploratory drilling costs to locate proved reserves are capitalized.

We are also exposed to potential impairments if the book value of our assets exceeds their future expected cash flows. This may occur if a field discovers lower than anticipated reserves or if commodity prices fall below a level that significantly effects anticipated future cash flows on the field. We determine if an impairment has occurred through either adverse changes or as a result of the annual review of all fields. The impairment of unamortized capital costs is measured at a lease level and is reduced to fair value if it is determined that the sum of expected future net cash flows is less than the net book value.

Oil and Gas Reserves

The process of estimating quantities of proved reserves is inherently uncertain, and the reserve data included in this document are only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and crude oil that cannot be measured in an exact manner. The process relies on interpretations of available geologic, geophysic, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Our proved reserve information included in this document is based on estimates we prepared. Estimates prepared by others may be higher or lower than our estimates.

Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of natural gas and crude oil that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

Our rate of recording depreciation, depletion and amortization expense (DD&A) is dependent upon our estimate of proved reserves. If the estimates of proved reserves declines, the rate at which we record DD&A expense increases, reducing net income. Such a decline may result from lower market prices, which may make it non-economic to drill for and produce higher cost fields. In addition, the decline in proved reserve estimates may impact the outcome of our annual impairment test under SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" when adopted.

Operating Risks and Insurance Coverage

Our business involves a variety of operating risks, including:

- blowouts, cratering and explosions;
- mechanical problems;
- uncontrolled flows of oil, natural gas or well fluids;
- fires;

- formations with abnormal pressures;
- pollution and other environmental risks; and
- natural disasters.

The operation of our natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites, could increase these risks. Any of these events could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations. The costs of these insurance policies are somewhat dependent on our historical claims experience and also the areas in which we choose to operate. During the past few years, we have drilled a higher percentage of our wells in the Gulf Coast, where insurance rates are significantly higher than in other regions such as Appalachia.

OTHER ISSUES AND CONTINGENCIES

Corporate Income Tax. We generate tax credits for the production of certain qualified fuels, including natural gas produced from tight sands formations and Devonian Shale. The credit for natural gas from a tight sand formation (tight gas sands) amounts to $0.52 per Mmbtu for natural gas sold prior to 2003 from qualified wells drilled in 1991 and 1992. A number of wells drilled in the Appalachian region and Rocky Mountains during 1991 and 1992 qualified for the tight gas sands tax credit. The credit for natural gas produced from Devonian Shale is estimated to be $1.08 per Mmbtu in 2001. In 1995 and 1996, we completed three transactions to monetize the value of these tax credits, resulting in revenues of $2.0 million in 2001 and an estimated $2.1 million in 2002. See Note 13 of the Notes to the Consolidated Financial Statements for further discussion.

We have benefited in the past and may benefit in the future from the alternative minimum tax (AMT) relief granted under the Comprehensive National Energy Policy Act of 1992 (the Act). The Act repealed provisions of the AMT requiring a taxpayer's alternative minimum taxable income to be increased on account of certain intangible drilling costs (IDC) and percentage depletion deductions. The repeal of these provisions generally applies to taxable years beginning after 1992. The repeal of the excess IDC preference can not reduce a taxpayer's alternative minimum taxable income by more than 40% of the amount of such income determined without regard to the repeal of such preference.

Regulations. Our operations are subject to various types of regulation by federal, state and local authorities. See Regulation of Oil and Natural Gas Production and Transportation and Environmental Regulations in the Other Business Matters section of Item 1 Business for a discussion of these regulations.

Restrictive Covenants. Our ability to incur debt and to make certain types of investments is subject to certain restrictive covenants in the Company's various debt instruments. Among other requirements, our Revolving Credit Agreement and the Notes (see Note 5 of the Notes to the Consolidated Financial Statements) specify a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0. At December 31, 2001, the calculated ratio for 2001 was 10.0 to 1.0. In the unforeseen event that we fail to comply with these covenants, the Company may apply for a temporary waiver with the bank, which, if granted, would allow us a period of time to remedy the situation. See further discussion in Capital Resources and Liquidity and Note 5 of the Notes to the Consolidated Financial Statements for further discussion.

CONCLUSION

Our financial results depend upon many factors, particularly the price of natural gas and oil and our ability to market gas on economically attractive terms. The average produced natural gas sales price received by us has changed from year-to-year as follows:

2001: increased 37% over 2000 to $4.36 per Mcf
2000: increased 44% over 1999 to $3.19 per Mcf
1999: increased 3% over 1998 to $2.22 per Mcf
1998: decreased 15% from 1997 to $2.16 per Mcf
1997: increased 8% over 1996 to $2.53 per Mcf

The volatility of natural gas prices in recent years remains prevalent in 2002 with wide price swings in day-to-day trading on the NYMEX futures market. Given this continued price volatility, we can not predict with certainty what pricing levels will be in the future. Because future cash flows are subject to these variables, there is no assurance that our operations will provide cash sufficient to fully fund our planned capital expenditures.

While our 2002 plan now includes $104.6 million in capital and exploration spending, we will periodically assess industry conditions and adjust our 2002 spending plan to ensure the adequate funding of our capital requirements, including, if necessary, reductions in capital and exploration expenditures or common stock dividends. We believe our capital resources, supplemented with external financing if necessary, are adequate to meet our capital requirements.

The preceding paragraphs contain forward-looking information. See Forward-Looking Information on page 32.

Recently Issued Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statements of Financial Accounting Standards No. 141 "Business Combinations" ("SFAS 141") and No. 142 "Goodwill and Other Intangible Assets" ("SFAS 142"). SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for under the purchase method. For all business combinations for which the date of acquisition is after June 30, 2001, SFAS 141 also establishes specific criteria for the recognition of intangible assets separately from goodwill. SFAS 141 also requires unallocated negative goodwill (in a case where the purchase price is less than fair market value of the acquired assets) to be written off immediately as an extraordinary gain, rather than deferred and amortized. SFAS 142 changes the accounting for goodwill and other intangible assets after an acquisition. The most significant changes made by SFAS 142 are: 1) goodwill and intangible assets with indefinite lives will no longer be amortized; 2) goodwill and intangible assets with indefinite lives must be tested for impairment at least annually; and 3) the amortization period for intangible assets with finite lives will no longer be limited to forty years. The Company does not believe that the adoption of these statements will have a material effect on its financial position, results of operations, or cash flows.

In June 2001, the FASB also approved for issuance SFAS 143 "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets such as wells and production facilities. SFAS 143 guidance covers (1) the timing of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company will adopt the statement effective no later than January 1, 2003, as required. The transition adjustment resulting from the adoption of SFAS 143 will be reported as a cumulative effect of a change in accounting principle. At this time, the Company cannot reasonably estimate the effect of the adoption of this statement on its financial position, results of operations, or cash flows.

In August 2001, the FASB also approved SFAS 144, "Accounting for the Impairment or Disposal of Long-

Lived Assets" ("SFAS 144"). SFAS 144 replaces SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." The new accounting model for long-lived assets to be disposed of by sale applies to all long-lived assets, including discontinued operations, and replaces the provisions of APB Opinion No. 30, "Reporting Results of Operations-Reporting the Effects of Disposal of a Segment of a Business", for the disposal of segments of a business. SFAS 144 requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS 144 also broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of SFAS 144 are effective for financial statements issued for fiscal years beginning after December 15, 2001 and, generally are to be applied prospectively. At this time, the Company cannot estimate the effect of this statement on its financial position, results of operations, or cash flows.

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Forward-Looking Information

The statements regarding future financial and operating performance and results, market prices, future hedging activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "forecast," "predict," "may," "should," "could" and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including regional basis differentials) of natural gas and oil, results for future drilling and marketing activity, future production and costs and other factors detailed herein and in our other Securities and Exchange Commission filings. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

RESULTS OF OPERATIONS

For the purpose of reviewing our results of operations, "Net Income" is defined as net income available to common stockholders.

Selected Financial and Operating Data

(In millions except where specified)	2001	2000	1999
Operating Revenues	$447.0	$368.7	$294.0
Operating Expenses	351.7	303.8	258.5
Operating Income	95.4	64.8	39.5
Interest Expense	20.8	22.9	25.8
Net Income	47.1	29.2	5.1
Earnings Per Share - Basic	$ 1.56	$ 1.07	$ 0.21
Earnings Per Share - Diluted	$ 1.53	$ 1.06	$ 0.21
Natural Gas Production (Bcf)			
Gulf Coast	25.6	14.1	15.5
West	26.2	29.0	29.3
Appalachia	17.4	17.8	20.7
Total Company	69.2	60.9	65.5
Produced Natural Gas Sales Price ($/Mcf)			
Gulf Coast	$ 4.44	$ 3.79	$ 2.29
West	3.88	2.86	1.96
Appalachia	4.96	3.24	2.53
Total Company	$ 4.36	$ 3.19	$ 2.22
Crude/Condensate			
Volume (Mbbl)	1,908	953	929
Price ($/Bbl)	$24.91	$26.81	$17.22

The table below presents the after-tax effects of certain selected items on our results of operations for the three years ended December 31, 2001.

(In millions)	2001	2000	1999
Net Income Before Selected Items	$ 51.9	$ 30.2	$ 0.4
Change in Derivative Fair Value	0.1		
Severance Tax Refund	0.7		
Buyout of Gas Sales Contract			7.3
Impairment of Long-Lived Assets	(4.2)	(5.6)	(4.3)
Gain on Sale of Assets			2.4
Section 29 Tax Credit Provision			(0.7)
Negative Preferred Stock Dividend		5.1	
Contract Settlements		1.4	
Bad Debt Expense	(1.4)	(1.3)	
Severance Costs		(0.6)	
Net Income	$ 47.1	$ 29.2	$ 5.1

These selected items impacted our financial results. Because they are not a part of our normal business, we have isolated their effects in the table above. These selected items for 2001 were as follows:

- The change in derivative fair value 2001 related to the adoption of SFAS 133 on January 1, 2001. See Note 11 of the Notes to the Consolidated Financial Statements for further discussion.

- A severance tax refund of $0.7 million ($1.1 million pre-tax) was received in the third quarter for taxes previously paid in Louisiana that recently qualified for the Severance Tax Relief Program as deep wells.

- A total impairment of $4.2 million ($6.9 million pre-tax) recorded in 2001. Two fields in the Gulf Coast region were impaired in the third quarter since the cost capitalized exceeded the future undiscounted cash flows. Also, one natural gas processing plant in the Rocky Mountains area was written down to fair market value. In the fourth quarter, the Starpath prospect in the Gulf Coast region was impaired.

- As a result of the Enron bankruptcy, we recorded $1.4 million ($2.3 million pre-tax) of bad debt expense primarily related to physical natural gas sales made to Enron in November 2001.

These selected items for 2000 were as follows:

- A $9.1 million impairment ($5.6 million after tax) was recorded on the Beaurline field in south Texas as a result of a casing collapse in two of the field's wells.

- As a result of repurchasing all of the preferred stock at less than the book value, we recorded a $5.1 million negative stock dividend in May 2000.

- Miscellaneous net revenue, primarily from the settlement of a natural gas sales contract, was recorded in the first quarter ($1.4 million after tax). See Note 13 of the Notes to the Consolidated Financial Statements for further discussion.

- As a result of bankruptcy proceedings of two of our customers, we recorded $2.1 million in bad debt expense in the fourth quarter ($1.3 million after tax).

- We announced the closure of the regional office in Pittsburgh in May 2000 and recorded costs of $1.0 million ($0.6 million after tax). These costs were recorded in the income statement categories that will receive the future savings benefit ($0.6 million in operations, $0.1 million in exploration and $0.3 million in administration).

These selected items for 1999 were as follows:

- We had a 15-year cogeneration contract under which we sold approximately 20% of our Western region natural gas per year. The contract was due to expire in 2008, but during 1999 we reached an agreement with the counterparty under which the counterparty bought out the remainder of the contract for $12 million. This transaction, completed in December 1999, accelerated the realization of any future price premium that may have been associated with the contract and added $12 million of pre-tax other revenue ($7.3 million after tax). We simultaneously sold forward a similar quantity of Western region gas production through April 2001 at similar prices to those in the old contract. The natural gas sales price stated in this new contract was significantly below year-end 2000 market prices in the region. See Note 13 of the Notes to the Consolidated Financial Statements for further discussion.

- In the fourth quarter of 1999, we recorded impairments totaling $7 million on two of our producing fields in the Gulf Coast region ($4.3

million after tax). The Chimney Bayou field was impaired by $6.6 million due to a significant reserve revision on the Broussard-Middleton #1R well in connection with a decline in its natural gas production accompanied by a marked increase in water production. The Broussard-Middleton #1R was the only producing well in this field. The Lawson field was impaired by $0.4 million due to an unsuccessful workover on one of its wells.

- We recorded a $4 million gain on the sale of certain non-strategic oil and gas assets, most notably the Clarksburg properties in the Appalachian region sold to EnerVest effective October 1999 ($2.4 million after tax).

- We recorded a $1.2 million reserve against other revenue for certain wells no longer deemed to be eligible for the Section 29 tight gas sands credit following an industry tax court ruling ($0.7 million after tax). Late in 1999, the FERC issued a rule proposal that may ultimately restore the eligibility for some or all of the wells in question. For an update on the FERC's actions, please read Note 13 of the Notes to the Consolidated Financial Statements.

2001 and 2000 Compared

The following discussion is based on our results before taking into account the selected items discussed above.

Net Income and Revenues. We reported net income in 2001 of $51.9 million, or $1.71 per share. During 2000, we reported net income of $30.2 million, or $1.10 per share. Operating income increased $28.5 million, or 38%, and operating revenues increased $80.6 million, or 22%, in 2001. The improvement in operating revenues was mainly a result of the $107.3 million rise in natural gas sales due to the increases in both natural gas prices and production, and the $22.0 million increase in crude oil sales revenue. Natural gas revenue and our realized price were bolstered by a $34.6 million gain on natural gas price collar arrangements used during 2001. See further discussion in Item 7A. These improvements were partially offset by a decline in brokered natural gas volume that reduced operating revenues by $50.4 million. Operating income was similarly impacted by these revenue changes.

The average Gulf Coast natural gas production sales price rose $0.65 per Mcf, or 17%, to $4.44, increasing operating revenues by approximately $16.6 million. In the Western region, the average natural gas production sales price increased $1.02 per Mcf, or 36%, to $3.88, increasing operating revenues by approximately $26.7 million. The average Appalachian natural gas production sales price increased $1.72 per Mcf, or 53%, to $4.96, increasing operating revenues by approximately $29.9 million. The overall weighted average natural gas production sales price increased $1.17 per Mcf, or 37%, to $4.36 per Mcf in 2001.

Natural gas production volume in the Gulf Coast region was up 11.5 Bcf, or 82%, to 25.6 Bcf primarily due to production from our discoveries in south Louisiana and production from the Cody Company properties acquired in August 2001. Natural gas production volume in the Western region was down 2.8 Bcf, or 10%, to 26.2 Bcf due primarily to lower levels of drilling activity in the Mid-Continent area during the past three years. Natural gas production volume in the Appalachian region was down 0.4 Bcf, or 2%, to 17.4 Bcf, as a result of lower than anticipated success of the Oriskany drilling program in the region in late 2000 and into 2001. Total natural gas production was up 8.3 Bcf, or 14%, in 2001.

Crude oil prices fell $1.90 per Bbl, or 7%, to $24.91, resulting in a decrease to operating revenues of approximately $3.6 million. The volume of crude oil sold in the year doubled to 1,908 Mbbls, increasing operating revenues by $25.6 million. This production increase was a result of our 2000 drilling success in south Louisiana (80% increase) and the acquisition of Cody Company (20% increase).

Brokered natural gas revenue decreased $50.4 million, or 36%, from the prior year. The sales price of brokered natural gas rose 37%, resulting in an increase in revenue of $24.5 million. The volume of natural gas brokered this year declined by 53%, reducing revenues by $74.9 million. After including the related brokered natural gas costs, we realized a net margin of $2.9 million in 2001 compared to a net margin of $5.4 million in 2000.

Excluding the selected items regarding the contract settlements in 2000, other operating revenues increased $1.6 million to $7.1 million. This increase in 2001 is primarily the result of a settlement received as a result of a lawsuit and increased revenue from the sale of natural gas liquids.

Costs and Expenses. Total costs and expenses from operations, excluding the selected items related to the impairment of long-lived assets and bad debt in each year and the costs associated with closing the regional office in Pittsburgh during 2000, increased $52.1 million, or 18%, from 2000 due primarily to the following:

- Brokered natural gas cost decreased $47.9 million, or 35%, primarily due to the $73.0 million impact of the lower volume of brokered sales in 2001. This was partially offset by a $25.1 million increase due to higher natural gas costs compared to the prior year.

- Production and pipeline expense increased $6.0 million, or 17%, primarily as a result of costs associated with operating the Cody Company properties acquired in August 2001. Additionally, increased staffing and insurance costs were incurred to support the expanded 2001 drilling program. On a units-of-production basis, our company-wide production and pipeline expense was $0.51 per Mcfe in 2001 versus $0.53 per Mcfe in 2000 as a result of the increased production discussed above.

- Exploration expense increased $51.4 million, or 261%, primarily as a result of the following:

    - A $15.3 million increase in geological and geophysical expenses over last year due to the acquisition of seismic data for future evaluation and increased drilling activity in all regions.

    - A $34.9 million increase in dry hole costs. Although the drilling success rate improved from 86% in 2000 to 87% in 2001, we drilled a total of 208 gross wells in 2001, a 61% increase over 2000. We recorded seven exploratory dry holes in the higher cost Gulf Coast region versus only two in 2000. We also recorded four exploratory dry holes in the Rocky Mountains area and seven in the Appalachian region for a total of 18, up from a Company total of seven in 2000.

    - A $0.8 million increase for salaries, wages and incentive compensation largely attributable to increased staffing in the Gulf Coast region to support the expanded drilling program.

- Depreciation, depletion, amortization and impairment expense, excluding the selected item related to the SFAS 121 impairment in each year, increased $30.6 million, or 53%, over 2000. Natural gas equivalent production increased 21%, increasing DD&A expense by $12.3 million. The 27% increase in the per unit expense from $0.86 per Mcfe to $1.09 per Mcfe was a result of increased production in the higher cost Gulf Coast region (including the newly acquired Cody properties) and resulted in an $18.3 million increase to DD&A expense for 2001.

- General and administrative expenses increased $5.5 million, primarily as a result of increased staffing during the transition period following the Cody Company acquisition and other staffing increases that support our larger operations. Additional cost increases were realized in incentive compensation programs as well as technology updates and related software maintenance.

- Taxes other than income increased $6.4 million as a result of higher natural gas and oil revenues.

Interest expense decreased $2.1 million due to a lower weighted average interest rate realized in 2001. This was despite the new Notes issued to partially fund the acquisition of Cody Company in August 2001.

Income tax expense was up $10.2 million due to the comparable increase in earnings before income tax. Our effective tax rate decreased in 2001 reflecting a shift of activity between states.

2000 and 1999 Compared

The following discussion is based on our results before taking into account the selected items discussed above.

Net Income and Revenues. We reported net income in 2000 of $30.2 million, or $1.10 per share. During 1999, we reported net income of $0.4 million, or $0.02 per share. Operating income increased $42.9 million, or 135%, and operating revenues increased $83.1 million, or 29%, in 2000. The improvement in operating revenues was mainly a result of the $48.7 million rise in natural gas sales due to the increase in gas prices, and the $24.5 million increase in brokered natural gas sales revenue. Operating revenues were reduced by a $10 million loss on natural gas price collar arrangements used during 2000. See further discussion in Item 7A. Price and production volume increases in crude oil also contributed to the higher operating revenues. Operating income was similarly impacted by these revenue changes.

The average Gulf Coast natural gas production sales price rose $1.50 per Mcf, or 66%, to $3.79, increasing operating revenues by approximately $21.2 million. In the Western region, the average natural gas production sales price increased $0.90 per Mcf, or 46%, to $2.86, increasing operating revenues by approximately $24.9 million. The average Appalachian natural gas production sales price increased $0.71 per Mcf, or 28%, to $3.24, increasing operating revenues by approximately $12.7 million. The overall weighted average natural gas production sales price increased $0.97 per Mcf, or 44%, to $3.19, increasing revenues by $58.8 million.

Natural gas production volume in the Gulf Coast region was down 1.4 Bcf, or 9%, to 14.1 Bcf primarily due to production difficulties in the Beaurline field and delays in bringing new production on-line in south Louisiana. Natural gas production volume in the Western region was down 0.3 Bcf to 29.0 Bcf due primarily to lower levels of drilling activity in the Mid-Continent area during 1999 and 2000. Natural gas production volume in the Appalachian region was down 2.9 Bcf to 17.8 Bcf, as a result of the sale of certain non-strategic assets in the Appalachian region effective October 1, 1999, and a decrease in drilling activity in the region. Total natural gas production was down 4.6 Bcf, or 7%, generating a revenue decrease of $10.1 million in 2000.

Crude oil prices rose $9.59 per Bbl, or 56%, to $26.81, resulting in an increase to operating revenues of approximately $9.2 million. The volume of crude oil sold in the year increased slightly to 953 Mbbls, increasing operating revenues by $0.4 million.

Brokered natural gas revenue increased $24.5 million, or 21%, over the prior year. The sales price of brokered natural gas rose 52%, resulting in an increase in revenue of $48.5 million. The volume of natural gas brokered this year declined by 21%, reducing revenues by $24.0 million. After including the related brokered natural gas costs, we realized a net margin of $5.4 million in 2000.

Excluding the selected items regarding the contract settlements in 2000, and the sales contract buyout and the Section 29 tax credit provision in 1999, other operating revenues increased $0.2 million to $5.5 million.

Costs and Expenses. Total costs and expenses from operations, excluding the selected items related to the impairment of long-lived assets in each year and the costs associated with closing the regional office in Pittsburgh during 2000, increased $40.2 million, or 16%, from 1999 due primarily to the following:

- Brokered natural gas cost increased $23.5 million, or 21%, primarily due to the $46.5 million impact of higher purchased natural gas prices. This was partially offset by a $23.0 million reduction to purchased natural cost, the result of fewer brokered sales this year compared to the prior year.

- Production and pipeline expense increased $1.9 million, or 6%, primarily as a result of costs associated with the expansion of the Gulf Coast regional office, both in staffing and office facilities. Additionally, operational costs for surface equipment and compressor maintenance were up in the Rocky Mountains area where we drilled 50% more net wells in 2000 compared to 1999. On a units-of-production basis, our company-wide production and pipeline expense was $0.53 per Mcfe in 2000 versus $0.47 per Mcfe in 1999.

- Exploration expense increased $8.3 million, or 72%, primarily as a result of the following:

    - A $3.5 million increase in geological and geophysical expenses over last year due to increased drilling activity in all regions.

    - A $1.3 million increase in delay rental costs over last year largely due to delays in scheduled drilling projects in the Gulf Coast region.

    - A $2.1 million increase for salaries, wages and incentive compensation largely attributable to increased staffing in the Gulf Coast region to support the expanded drilling program.

    - A $0.5 million increase in dry hole costs. Although the drilling success rate improved from 84% in 1999 to 86% in 2000, we recorded two exploratory dry holes in the higher cost Gulf Coast region versus only one in 1999.

- Depreciation, depletion, amortization and impairment expense, excluding the selected item related to the SFAS 121 impairment in each year, increased $0.5 million, or 1%, over 1999. A 6% decrease in total natural gas equivalent production caused the expense to remain just slightly above last year's level, despite the 7% increase in the per unit expense to $0.86 per Mcfe.

- General and administrative expenses remained at the same level as in 1999.

- Taxes other than income increased $6.1 million as a result of higher natural gas and oil revenues.

Interest expense decreased $2.9 million primarily due to lower average levels of borrowing on the revolving credit facility.

Income tax expense was up $18.1 million due to the comparable increase in earnings before income tax.

No significant asset sale activity occurred in 2000. Gain on the sale of assets was $4 million for 1999. These gains are the result of the non-strategic asset divestitures, primarily the sale of the Clarksburg properties in the

Appalachian region to EnerVest effective October 1999.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Oil and gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and, to a lesser extent, oil. Declines in oil and natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil and gas prices also may reduce the amount of oil and gas that we can produce economically. Historically, oil and gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Oil and gas prices declined substantially in 1998 and early 1999, moved higher through 2000 and into 2001 before declining back to year-end 1998 levels in October 2001. Because our reserves are predominantly natural gas, changes in natural gas prices may have a particularly significant impact on our financial results.

Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- The domestic and foreign supply of oil and natural gas.

- The level of consumer product demand.

- Weather conditions.

- Political conditions in oil producing regions, including the Middle East.

- The ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls.

- The price of foreign imports.

- Actions of governmental authorities.

- Domestic and foreign governmental regulations.

- The price, availability and acceptance of alternative fuels.

- Overall economic conditions.

These factors make it impossible to predict with any certainty the future prices of oil and gas.

Our hedging policy is designed to reduce the risk of price volatility for our production in the natural gas, natural gas liquids and crude oil markets. Currently we are focusing on protection from natural gas price declines, particularly in light of our capital spending plans. A hedging committee that consists of members of senior management overseas our hedging activity. Our hedging arrangements apply to only a portion of our production and provide only partial price protection against declines in oil and gas prices. These hedging arrangements may expose us to risk of financial loss and limit the benefit to us of increases in prices. Please read the discussion below related to commodity price swaps and Note 11 of the Notes to the Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

Commodity Price Swaps and Options

Hedges on Production - Swaps

From time to time, we enter into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of our production. These derivatives are not held for trading purposes. Under these price swaps, we receive a fixed price on a notional quantity of natural gas and crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures. During 2001, we fixed the price at an average of $3.75 per Mcf on quantities totaling 918 Mmcf, representing 1% of the Company's 2001 natural gas production. We did not have crude oil swap arrangements covering our production in 2001. During 2000, we fixed the price at an average of $4.54 per Mcf on quantities totaling 315 Mmcf, representing less

than 1% of the Company's 2000 natural gas production. The notional volume of the crude oil swap transactions was 364 Mbbls at a price of $22.67 per Bbl, which represented approximately 38% of our total oil production for 2000. During 1999, we fixed the price at an average of $2.88 per Mcf on quantities totaling 3,237 Mmcf, representing 5% of the Company's 1999 natural gas production. The notional volume of the crude oil swap transactions was 306 Mbbls at a price of $20.65 per Bbl, which represented approximately one-third of our total oil production for 1999.

The natural gas price swap arrangement that we entered into during the third quarter of 2000 covered a portion of production over the period of October 2000 through September 2003. However, the counterparty declared bankruptcy in

December 2001. Based on the terms of the natural gas swap contract, this action resulted in the cancellation of the contract. At the time of cancellation, the contract's value was less than $0.2 million. As of the years ending December 31, 2001, and 2000, we had open natural gas price swap contracts on our production as follows:

	Natural Gas Price Swaps		
Contract Period	Volume in Mmcf	Weighted Average Contract Price	Unrealize Gain/(Los (in $ milli
As of December 31, 2001			
None			
As of December 31, 2000			
Natural Gas Price Swaps on Production in:			
Full Year 2001	918	$3.75	$(2.8)
Full Year 2002	678	3.11	(1.0)
Full Year 2003	423	2.81	(0.5)

Financial derivatives related to natural gas production reduced revenues by $0.8 million in 2001 and $0.3 million in 2000.

We had no open oil price swap contracts outstanding on our production at December 31/st/ of 2001 or 2000. Financial derivatives related to crude oil reduced revenue by $2.2 million during 2000, but had no impact on 2001 results.

Hedges on Production - Options

In December 2000, we believed that the pricing environment provided a strategic opportunity to significantly reduce the price risk on a portion of our production through the use of costless collars. Under the costless collar arrangements, if the index rises above the ceiling price, we pay the counterparty. If the applicable index falls below the floor, the counterparty pays us. The 2001 natural gas price hedges include several costless collar arrangements based on eight price indexes at which we sell a portion of our production. These hedges were in place for the months of February through October 2001 and covered 24,404 Mmcf, or 35%, of our natural gas production for the year. All indexes were within the collars during February and April, some fell below the floor during the period of March, and all indexes were below the floor from June through October, resulting in a $34.6 million cash revenue for the year. These gains contributed $0.50 per Mcf to our average realized natural gas price for 2001.

During 2000, we used several costless collar arrangements to hedge a portion of our natural gas production. There were seven collar arrangements based on separate regional price indexes with a weighted average price floor of $2.74 per Mcf and a weighted average price ceiling of $3.38 per Mcf. These collars were in place during the months of April through October 2000. During this period, if the index rose above the ceiling price, we paid the counterparty. If the applicable index fell below the floor price, the counterparty paid us. These collars covered a total quantity of 9,909 Mmcf, or 16% of our annual production. In April and May 2000, the index prices all fell within the price collar and no settlements were made. In June 2000, all of the indexes rose above the ceiling prices and remained above the ceiling for the duration of the transaction resulting in a $10 million reduction to our realized revenue for the year. If these hedges had not been in place, our average realized natural gas price for 2000 would have been $0.17 per Mcf higher.

Again in December of 2001, we believed that the pricing environment provided a strategic opportunity to significantly reduce the price risk on a portion of our future production through the use of natural gas price collar arrangements. As of December 31, 2001, we had open natural gas price collar arrangements to hedge our production as follows:

	Natural Gas Price Col		
Contract Period	Volume in Mmcf	Weighted Average Ceiling / Floor	(i
As of December 31, 2001			
Natural Gas Collars on Production in:			
First Quarter of 2002	12,082	$3.54/$2.68	
Second Quarter of 2002	4,027	$3.54/$2.68	
As of December 31, 2000			
Natural Gas Costless Collars on Production in:			
First Quarter of 2001	5,274	$9.68/$5.59	
Second Quarter of 2001	8,135	$9.68/$5.59	
Third Quarter of 2001	8,224	$9.68/$5.59	
Fourth Quarter of 2001	2,771	$9.68/$5.59	

The natural gas price hedges open at December 31, 2001, noted above, included several collar arrangements based on nine price indexes at which we sell a portion of our production. These hedges are in place for the months of January through April 2002 and cover approximately 60% of our anticipated natural gas production during this period. A premium totaling $0.9 million was paid to purchase these collar arrangements.

Hedges on Brokered Transactions

We use price swaps to hedge the natural gas price risk on brokered transactions. Typically, we enter into contracts to broker natural gas at a variable price based on the market index price. However, in some circumstances, some of our customers or suppliers request that a fixed price be stated in the contract. After entering into these fixed price contracts to meet the needs of our customers or suppliers, we may use price swaps to effectively convert these fixed price contracts to market-sensitive price contracts. These price swaps are held by us to their maturity and are not held for trading purposes.

We entered into price swaps with total notional quantities of 1,295 Mmcf in 2000 and 3,572 Mmcf in 1999 related to our brokered activities, representing 3% and 7% respectively, of our total volume of brokered natural gas sold. We did not use price swaps on brokered transactions in 2001.

As of the years ending December 31, 2000 and 2001, we had no open natural gas price swap contracts on brokered transactions. Financial derivatives related to natural gas reduced revenues by less than $0.1 million in 2000 and had no impact on revenue in 2001.

We are exposed to market risk on these open contracts, to the extent of changes in market prices of natural gas and oil. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged.

Adoption of SFAS 133

We adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) on January 1, 2001. Under SFAS 133, the fair value of each derivative instrument is recorded as either an asset or liability on the balance sheet. At the end of each period, these instruments are marked-to-market. The gain or loss on the change in fair value is recorded as Other Comprehensive Income, a component of equity, to the extent that the derivative instrument is an effective hedge. Under SFAS 133, effectiveness is a measurement of how closely correlated the hedge instrument is with the underlying physical sale. For example, a natural gas price swap that converts Henry Hub index to a fixed price would be perfectly correlated,

and 100% effective, if the underlying gas was sold at the Henry Hub index. Any portion of the gains or losses that are considered ineffective under the SFAS 133 test are recorded immediately as a component of operating revenue on the statement of operations.

When we adopted SFAS 133, we had two types of hedges in place. The first type was a cash flow hedge that set the price of a certain monthly quantity of natural gas sold in the Gulf Coast region through September 2003. Based on the index price strip, the impact of this hedge on January 1, 2001 was to record a Hedge Loss of $0.1 million and a charge to Other Comprehensive Income of $4.2 million. Correspondingly, a Hedge Liability for $4.3 million was established. This instrument was cancelled in December 2001 with the bankruptcy of the counterparty. No balance related to this hedge remains in Other Comprehensive Income.

The second type of hedge outstanding at January 1, 2001 was a natural gas price costless collar agreement. We had entered into eight of these collars for a portion of our production at regional indexes for the months of February through October 2001. The collars had two components of value: intrinsic value and time value. Under SFAS 133, both components were valued at the end of each reporting period. Intrinsic value arises when the index price is either above the ceiling or below the floor for any period covered by the collar. If the index is above the ceiling for any month covered by the collar, the intrinsic value would be the difference between the index and the ceiling prices multiplied by the notional volume. In accordance with the initial SFAS 133 guidance, intrinsic value related to the current month would be recorded as a hedge loss (if the index is above the ceiling) or gain (if the index is below the floor). Starting in 2001 under amended guidance on SFAS 133, any changes in the intrinsic value component related to future months were recorded in Other Comprehensive Income, a component of stockholders' equity on the balance sheet, rather than to the income statement to the extent that the hedge was proven to be effective. These natural gas price collars were considered to be highly effective with respect to the intrinsic value calculation, since they were tied to the same indexes at which our natural gas is sold. Also under SFAS 133, the time value component, a market premium/discount, was marked-to-market through the income statement each period. Since these collar arrangements were executed on the last business day of 2000, the net premium value at adoption on January 1, 2001 was zero.

As of December 31, 2001, we had a series of nine natural gas price collar arrangements in place. In accordance with the latest guidance from the FASB's Derivative Implementation Group, we test the effectiveness of the combined intrinsic and time values and the effective portion of each will be recorded as a component of Other Comprehensive Income. Any ineffective portion will be recorded as a gain or loss in the current period. As of December 31, 2001, we have recorded $1.4 million of Other Comprehensive Income, a $0.1 million Unrealized Hedge Gain and a $1.5 million Hedge Asset.

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Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the consolidated balance sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value. The Company uses available marketing data and valuation methodologies to estimate fair value of debt.

Long-Term Debt

	December 31, 2001		December 31, 2000	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Debt				
10.18% Notes	$ --	$ --	$ 32,000	$ 33,162
7.19% Notes	100,000	104,961	100,000	97,033
7.26% Notes	75,000	79,187	--	--
7.36% Notes	75,000	79,225	--	--
7.46% Notes	20,000	21,097	--	--
Credit Facility	123,000	123,000	137,000	137,000
	$393,000	$407,470	$269,000	$267,195

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF MANAGEMENT

The management of Cabot Oil & Gas Corporation is responsible for the preparation and integrity of all information contained in the annual report. The consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States of America and, accordingly, include certain informed judgments and estimates of management.

Management maintains a system of internal accounting and managerial controls and engages internal audit representatives who monitor and test the operation of these controls. Although no system can ensure the elimination of all errors and irregularities, the 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 for financial statement preparation.

An Audit Committee of the Board of Directors, consisting of directors who are not employees of the Company, meets periodically with management, the independent accountants and internal audit representatives to obtain assurances to the integrity of the Company's accounting and financial reporting and to affirm the adequacy of the system of accounting and managerial controls in place. The independent accountants and internal audit representatives have full and free access to the Audit Committee to discuss all appropriate matters.

We believe that the Company's policies and system of accounting and managerial controls reasonably assure the integrity of the information in the consolidated financial statements and in the other sections of the annual report.

Ray Seegmiller
Chairman of the Board and Chief Executive Officer

February 22, 2002

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REPORT OF INDEPENDENT ACCOUNTANTS

To the Stockholders and Board of Directors of Cabot Oil & Gas Corporation:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Cabot Oil & Gas Corporation and its subsidiaries at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 11 to the Notes to the Consolidated Financial Statements, the Company changed its method of accounting for its derivative instruments and hedging activities in connection with its adoption of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended.

PricewaterhouseCoopers LLP

Houston, Texas
February 15, 2002

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CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended December 31,		
(In thousands, except per share amounts)	2001	2000	1999
OPERATING REVENUES			
Natural Gas Production	$301,529	$194,185	$145,495
Brokered Natural Gas	90,710	141,085	116,554
Crude Oil and Condensate	47,544	25,544	15,909
Change in Derivative Fair Value (Note 11)	142	--	--
Other (Note 13)	7,117	7,837	16,079
	447,042	368,651	294,037
OPERATING EXPENSES			
Brokered Natural Gas Cost	87,785	135,700	112,164
Production and Pipeline Operations	41,217	35,727	33,357
Exploration	71,165	19,858	11,490
Depreciation, Depletion and Amortization	80,619	53,441	53,357
Impairment of Unproved Properties	7,803	4,368	3,950
Impairment of Long-Lived Assets	6,852	9,143	7,047
General and Administrative	25,650	20,421	20,136
Bad Debt Expense (Note 3)	2,270	2,096	--
Taxes Other Than Income	28,341	23,041	16,988
	351,702	303,795	258,489
Gain (Loss) on Sale of Assets	26	(39)	3,950
INCOME FROM OPERATIONS	95,366	64,817	39,498
Interest Expense and Other	20,817	22,878	25,818
Income Before Income Tax Expense	74,549	41,939	13,680
Income Tax Expense	27,465	16,467	5,161
NET INCOME	47,084	25,472	8,519
Preferred Stock Dividend (Note 10)	--	(3,749)	3,402
Net Income Available to Common Stockholders	$ 47,084	$ 29,221	$ 5,117

Basic Earnings per Share Available to Common Stockholders	$ 1.56	$ 1.07	$ 0.21
Diluted Earnings per Share Available to Common Stockholders	$ 1.53	$ 1.06	$ 0.21
Average Common Shares Outstanding	30,276	27,384	24,726

The accompanying notes are an integral part of these consolidated financial statements.

CABOT OIL & GAS CORPORATION

CONSOLIDATED BALANCE SHEET

(In thousands, except share amounts)	December 31, 2001	2000
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 5,706	$ 7,574
Accounts Receivable	50,711	85,677
Inventories	17,560	11,037
Other	11,010	5,981
Total Current Assets	84,987	110,269
PROPERTIES AND EQUIPMENT (Successful Efforts Method)	981,338	623,174
OTHER ASSETS	2,706	2,191
	$1,069,031	$735,634
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Current Portion of Long-Term Debt	$ --	$ 16,000
Accounts Payable	79,575	81,566
Accrued Liabilities	30,665	20,542
Total Current Liabilities	110,240	118,108
LONG-TERM DEBT	393,000	253,000
DEFERRED INCOME TAXES	200,859	108,174
OTHER LIABILITIES	18,380	13,847
COMMITMENTS AND CONTINGENCIES (Note 8)		
STOCKHOLDERS' EQUITY		
Preferred Stock		
Authorized - 5,000,000 Shares of $0.10 Par Value - 6% Convertible Redeemable Preferred; $50 Stated Value; No Shares Outstanding in 2001 and 2000 (Note 10)	--	--
Common Stock		
Authorized - 40,000,000 Shares of $0.10 Par Value Issued and Outstanding - 31,905,097 Shares in 2001 and 29,494,411 Shares in 2000	3,191	2,949
Class B Common Stock		
Authorized - 800,000 Shares of $0.10 Par Value No Shares Issued	--	--

Additional Paid-in Capital	346,260	285,572
Retained Earnings (Accumulated Deficit)	650	(41,632)
Other Comprehensive Income	835	--
Less Treasury Stock, at Cost		
302,600 Shares in 2001 and 2000	(4,384)	(4,384)
Total Stockholders' Equity	346,552	242,505
	$1,069,031	$735,634

The accompanying notes are an integral part of these consolidated financial statements.

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF CASH FLOWS

(In thousands)	Year Ended December 31, 2001	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 47,084	$ 25,472	$ 8,519
Adjustments to Reconcile Net Income			
to Cash Provided by Operations			
Depletion, Depreciation and Amortization	80,619	53,441	53,357
Impairment of Unproved Properties	7,803	4,368	3,950
Impairment of Long-Lived Assets	6,852	9,143	7,047
Deferred Income Tax Expense	14,157	13,162	9,060
(Gain) Loss on Sale of Assets	(26)	39	(3,950)
Exploration Expense	71,165	19,858	11,490
Change in Derivative Fair Value	(142)	--	--
Other	2,995	1,141	2,439
Changes in Assets and Liabilities			
Accounts Receivable	34,966	(35,286)	5,408
Inventories	(6,523)	(108)	(1,617)
Other Current Assets	(3,524)	(2,357)	164
Other Assets	(515)	348	598
Accounts Payable and Accrued Liabilities	(7,859)	26,976	(5,505)
Other Liabilities	3,383	2,813	1,528
Net Cash Provided by Operations	250,435	119,010	92,488
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital Expenditures	(127,129)	(99,359)	(82,191)
Acquisition of Cody Company /(1)/	(187,785)	--	--
Proceeds from Sale of Assets	6,829	3,150	56,328
Exploration Expense	(71,165)	(19,858)	(11,490)
Net Cash Used by Investing	(379,250)	(116,067)	(37,353)

CASH FLOWS FROM FINANCING ACTIVITIES

Increase in Debt	435,000	135,000	125,000
Decrease in Debt	(311,000)	(159,000)	(175,000)
Sale of Common Stock	7,749	85,104	1,738
Common Dividends Paid	(4,802)	(4,350)	(3,992)
Preferred Dividends Paid	--	(2,202)	(3,402)
Retirement of Preferred Stock	--	(51,600)	--
Net Cash Provided (Used) by Financing	126,947	2,952	(55,656)
Net Increase (Decrease) in Cash and Cash Equivalents	(1,868)	5,895	(521)
Cash and Cash Equivalents, Beginning of Year	7,574	1,679	2,200
Cash and Cash Equivalents, End of Year	$ 5,706	$ 7,574	$ 1,679

/1/ The amount excludes non-cash consideration of $49.9 million in common stock issued in connection with the acquisition of Cody Company in August 2001. This amount also excludes the $78.0 million deferred taxes pertaining to the difference between the fair value of the assets acquired and the related tax basis. The amount includes the $181.3 million in cash consideration plus $6.4 million in capitalized acquisition costs. See Note 14, Acquisition of Cody Company.

The accompanying notes are an integral part of these consolidated financial statements.

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(In thousands)	Common Shares	Stock Par	Preferred Stock	Treasury Stock	Paid-I Capita
Balance at December 31, 1998	24,960	$2,496	$ 113	$(4,384)	$252,07
Net Income					
Exercise of Stock Options	72	7			1,49
Preferred Stock Dividends					
Common Stock Dividends at $0.16 per Share					
Stock Grant Vesting	42	4			1,19
Other					
Balance at December 31, 1999	25,074	$2,507	$ 113	$(4,384)	$254,76
Net Income					
Exercise of Stock Options	766	77			14,76
Preferred Stock Dividends					
Common Stock Dividends at $0.16 per Share					
Stock Grant Vesting	254	25			1,41

Issuance of Common Stock	3,400	340			71,21
Retirement of Preferred Stock			(113)		(56,58
Balance at December 31, 2000	29,494	$2,949	$ --	$(4,384)	$285,57
Net Income					
Exercise of Stock Options	411	42			9,33
Common Stock Dividends at $0.16 per Share					
Other Comprehensive Income					
Stock Grant Vesting					1,68
Issuance of Common Stock	2,000	200			49,66
Balance at December 31, 2001	31,905	$3,191	$ --	$(4,384)	$346,26

The accompanying notes are an integral part of these consolidated financial statements.

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Year Ended December 31,		
(In thousands)	2001	2000	1999
Net Income Available to Common Stockholders	$ 47,084	$29,221	$5,117
Other Comprehensive Income			
Cumulative Effect of Change in Accounting Principle on January 1, 2001	(4,269)	--	--
Reclassification Adjustments for Settled Contracts	33,762	--	--
Changes in Fair Value of Outstanding Hedge Positions	(28,131)	--	--
Deferred Income Tax	(527)	--	--
Total Other Comprehensive Income	835	--	--
Comprehensive Income	$ 47,919	$29,221	$5,117

The accompanying notes are an integral part of these consolidated financial statements.

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Cabot Oil & Gas Corporation and its subsidiaries are engaged in the exploration, development, production and marketing of natural gas and, to a lesser extent, crude oil and natural gas liquids. The Company also transports, stores, gathers and purchases natural gas for resale. The Company operates in one segment, natural gas and oil exploration and exploitation within the continental United States.

The consolidated financial statements contain the accounts of the Company after eliminating all significant intercompany balances and transactions.

Recently Issued Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statements of Financial Accounting Standards No. 141 "Business Combinations" ("SFAS 141") and No. 142 "Goodwill and Other Intangible Assets" ("SFAS 142"). SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for under the purchase method. For all business combinations for which the date of acquisition is after June 30, 2001, SFAS 141 also establishes specific criteria for the recognition of intangible assets separately from goodwill. SFAS 141 also requires unallocated negative goodwill (in a case where the purchase price is less than fair market value of the acquired assets) to be written off immediately as an extraordinary gain, rather than deferred and amortized. SFAS 142 changes the accounting for goodwill and other intangible assets after an acquisition. The most significant changes made by SFAS 142 are: 1) goodwill and intangible assets with indefinite lives will no longer be amortized; 2) goodwill and intangible assets with indefinite lives must be tested for impairment at least annually; and 3) the amortization period for intangible assets with finite lives will no longer be limited to 40 years. The Company does not believe that the adoption of these statements will have a material effect on its financial position, results of operations or cash flows. The Company did not record goodwill as part of the Cody acquisition.

In June 2001, the FASB also approved for issuance SFAS 143 "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets such as wells and production facilities. SFAS 143 guidance covers (1) the timing of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company will adopt the statement effective no later than January 1, 2003, as required. The transition adjustment resulting from the adoption of SFAS 143 will be reported as a cumulative effect of a change in accounting principle. At this time, the Company cannot reasonably estimate the effect of the adoption of this statement on its financial position, results of operations or cash flows.

In August 2001, the FASB also approved SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"). SFAS 144 replaces SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." The new accounting model for long-lived assets to be disposed of by sale applies to all long-lived assets, including discontinued operations, and replaces the provisions of APB Opinion No. 30, "Reporting Results of Operations-Reporting the Effects of Disposal of a Segment of a Business", for the disposal of segments of a business. SFAS 144 requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS 144 also broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of SFAS 144 are

effective for financial statements issued for fiscal years beginning after December 15, 2001 and, generally are to be applied prospectively. At this time, the Company cannot estimate the effect of this statement on its financial position, results of operations, or cash flows.

Pipeline Exchanges

Natural gas gathering and pipeline operations normally include exchange arrangements with customers and suppliers. The volumes of natural gas due to or from the Company under exchange agreements are recorded at average selling or purchase prices, as the case may be, and are adjusted monthly to reflect market changes. The net value of exchanged natural gas is included in inventories in the consolidated balance sheet.

Properties and Equipment

The Company uses the successful efforts method of accounting for oil and gas producing activities. Under this method, acquisition costs for proved and unproved properties are capitalized when incurred. Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry hole drilling costs, are expensed. Development costs, including the costs to drill and equip development wells, and successful exploratory drilling costs to locate proved reserves are capitalized.

The impairment of unamortized capital costs is measured at a lease level and is reduced to fair value if it is determined that the sum of expected future net cash flows is less than the net book value. The Company determines if an impairment has occurred through either adverse changes or as a result of the annual review of all fields. During 2001, the Company recorded a total impairment of $6.9 million primarily related to three Gulf Coast fields for which capitalized cost exceeded the future undiscounted cash flows. Additionally, one natural gas processing plant in the Rocky Mountains was written down to fair market value. During 2000, two wells in the Beaurline field in south Texas experienced casing collapses. This situation resulted in an impairment to this field of $9.1 million, recorded in the second quarter financial results. During the fourth quarter of 1999, the Company experienced a significant production decline from the Chimney Bayou field located in the Texas Gulf Coast. This decline along with an unsuccessful workover in the Lawson field in Louisiana resulted in a $7.0 million impairment of long-lived assets during 1999. These impairments were measured based on discounted cash flows utilizing a discount rate appropriate for risks associated with the related properties.

Capitalized costs of proved oil and gas properties, after considering estimated dismantlement, restoration and abandonment costs, net of estimated salvage values, are depreciated and depleted on a field basis by the units-of-production method using proved developed reserves. The costs of unproved oil and gas properties are generally combined and amortized over a period that is based on the average holding period for such properties and the Company's experience of successful drilling. Properties related to gathering and pipeline systems and equipment are depreciated using the straight-line method based on estimated useful lives ranging from 10 to 25 years. Certain other assets are also depreciated on a straight-line basis.

Future estimated plug and abandonment costs are accrued over the productive life of the oil and gas properties on a units-of-production basis. The accrued liability for plug and abandonment costs is included in accumulated depreciation, depletion and amortization. As a component of accumulated depreciation, depletion and amortization, total future plug and abandonment costs were $14.4 million at December 31, 2001, and $12.4 million at December 31, 2000. The Company believes that this accrual method adequately provides for its estimated future plug and abandonment costs over the reserve life of the oil and gas properties.

The Company estimated at December 31, 2001 that it would ultimately require approximately $50.8 million to plug and abandon its properties at the end of their economic life occurring over the next 50 years. These costs would include plugging all wells, removing all equipment and returning all sites to the original condition. The Company anticipates these plugging and abandoning operations to occur throughout future years as each well is fully produced. Under SFAS 143, the Company will record the discounted present value of this amount as a component of the capitalized cost of proved oil and gas properties, and increase the future estimated liability monthly by recording implied interest. These costs will be expensed over the life of the reserves.

Costs of retired, sold or abandoned properties that make up a part of an amortization base (partial field) are charged to accumulated depreciation, depletion and amortization if the units-of-production rate is not significantly affected. Accordingly, a gain or loss, if any, is recognized only when a group of proved properties (entire field) that make up the amortization base has been retired, abandoned or sold.

Revenue Recognition and Gas Imbalances

The Company applies the sales method of accounting for natural gas revenue. Under this method, revenues are recognized based on the actual volume of natural gas sold to purchasers. Natural gas production operations may include joint owners who take more or less than the production volumes entitled to them on certain properties. Production volume is monitored to minimize these natural gas imbalances. A natural gas imbalance liability is recorded in other liabilities in the consolidated balance sheet if the Company's excess takes of natural gas exceed its estimated remaining proved reserves for these properties.

Brokered Natural Gas Margin

In prior years, the revenues and expenses related to brokering natural gas were reported net on the Consolidated Statement of Operations as Brokered Natural Gas Margin. Beginning in 2000, these amounts are reported gross as part of Operating Revenues and Operating Expenses. Prior year amounts have been reclassified to conform to the current year presentation.

The Company realizes brokered margin as a result of buying and selling natural gas in back-to-back transactions. The Company realized $2.9 million, $5.4 million, and $4.4 million of brokered natural gas margin in 2001, 2000, and 1999, respectively.

Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to turn around. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change.

Natural Gas Measurement

The Company records estimated amounts for natural gas revenues and natural gas purchase costs based on volumetric calculations under its natural gas sales and purchase contracts. Variances or imbalances resulting from such calculations are inherent in natural gas sales, production, operation, measurement, and administration. Management does not believe that differences between actual and estimated natural gas revenues or purchase costs attributable to the unresolved variances or imbalances are material.

Accounts Payable

This account includes credit balances from outstanding checks in zero balance cash accounts. These credit balances included in accounts payable were $9.7 million at December 31, 2001, and $12.7 million at December 31, 2000.

Risk Management Activities

From time to time, the Company enters into derivative contracts, such as natural gas price swaps or costless price collars, as a hedging strategy to manage commodity price risk associated with its inventories, production or other contractual commitments. These transactions are executed for purposes other than trading. Gains or losses on these hedging activities are generally recognized over the period that the inventory, production or other underlying

commitment is hedged as an offset to the specific hedged item. Cash flows related to any recognized gains or losses associated with these hedges are reported as cash flows from operations. If a hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period that the underlying production or other contractual commitment is delivered. Unrealized gains or losses associated with any derivative contract not considered a hedge would be recognized currently in the results of operations.

A derivative instrument qualifies as a hedge if all of the following tests are met:

.. The item to be hedged exposes the Company to price risk.
.. The derivative reduces the risk exposure and is designated as a hedge at the time the Company enters into the contract.
.. At the inception of the hedge and throughout the hedge period there is a high correlation between changes in the market value of the derivative instrument and the fair value of the underlying item being hedged.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on the sale or settlement of the underlying item. For example, in the case of natural gas price hedges, the gain or loss is reflected in natural gas revenue. When a derivative instrument is associated with an anticipated transaction that is no longer expected to occur or if correlation no longer exists, the gain or loss on the derivative is recognized currently in the results of operations to the extent the market value changes in the derivative have not been offset by the effects of the price changes on the hedged item since the inception of the hedge. See Note 11 Financial Instruments for further discussion.

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) and Statement of Financial Accounting Standards No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities" (SFAS 138). SFAS 133 requires all derivatives to be recognized in the statement of financial position as either assets or liabilities and measured at fair value. In addition, all hedging relationships must be designated, reassessed and documented according to the provisions of SFAS 133. SFAS 138 amended portions of SFAS 133 and was adopted with SFAS 133.

All hedge transactions are subject to the Company's risk management policy, approved by the Board of Directors, which does not permit speculative positions. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedge transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an quarterly basis going forward, the Company assesses whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

Cash Equivalents

The Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. At December 31, 2001, and 2000, the cash and cash equivalents are primarily concentrated in two financial institutions. The Company periodically assesses the financial condition of these institutions and believes that any possible credit risk is minimal.

Environmental Matters

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. Any insurance recoveries are recorded as assets when received.

Use of Estimates

In preparing financial statements, the Company follows generally accepted accounting principles. These principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The Company's most significant financial estimates are based on the remaining proved oil and gas reserves (see Supplemental Oil and Gas Information). Actual results could differ from those estimates.

2. Properties and Equipment

Properties and equipment are comprised of the following:

December 31,

(In thousands)	2001	2000
Proved Oil and Gas Properties	$1,400,341	$ 993,397
Unproved Oil and Gas Properties	70,709	31,780
Gathering and Pipeline Systems	131,768	128,257
Land, Building and Improvements	4,674	4,538
Other	27,513	25,601
	1,635,005	1,183,573
Accumulated Depreciation, Depletion, Amortization and Impairments	(653,667)	(560,399)
	$ 981,338	$ 623,174

As a component of accumulated depreciation, depletion and amortization, total future plug and abandonment costs were $14.4 million at December 31, 2001, and $12.4 million at December 31, 2000. See further discussion in Note 1.

On February 14, 2002, the Company determined that two exploratory wells (one in the Gulf Coast and one in Appalachia) were unsuccessful and would be abandoned. As of December 31, 2001, costs of approximately $7.7 million had been incurred on these wells and this amount is included as a component of Exploration Expense in the Statement of Operations. The Company anticipates recording additional pre-tax dry hole expense of $2.5 million in the first quarter of 2002 associated with drilling and abandoning these wells.

3. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

(In thousands)	December 31, 2001	2000
Accounts Receivable		
Trade Accounts	$39,570	$79,773
Joint Interest Accounts	12,889	4,074
Current Income Tax Receivable	2,662	37
Other Accounts	986	4,347
	56,107	88,231
Allowance for Doubtful Accounts /(1)/	(5,396)	(2,554)
	$50,711	$85,677

(1) Includes a $2.3 million addition in 2001 in connection with the Enron Corp. bankruptcy. Includes a $2.1 million addition in 2000 in connection with two trade receivable accounts determined not to be collectible due to bankruptcy filings of the customers.

(In thousands)	December 31, 2001	2000
Other Current Assets		

Derivative Instrument Asset - SFAS 133	$ 2,387	$ --
Drilling Advances	2,111	2,459
Prepaid Balances	2,114	2,172
Restricted Cash and Other Accounts /(1)/	4,398	1,350
	$11,010	$ 5,981
Accounts Payable		
Trade Accounts	$19,914	$23,757
Natural Gas Purchases	4,559	12,525
Wellhead Gas Imbalances	2,353	2,185
Royalty and Other Owners	11,041	22,858
Capital Costs	30,923	13,486
Taxes Other than Income	2,686	2,654
Drilling Advances	2,627	456
Other Accounts	5,472	3,645
	$79,575	$81,566
Accrued Liabilities		
Employee Benefits	$ 7,151	$ 5,441
Taxes Other than Income	13,623	11,363
Interest Payable	6,996	2,478
Other Accrued	2,895	1,260
	$30,665	$20,542
Other Liabilities		
Postretirement Benefits Other than Pension	$ 1,689	$ 1,497
Accrued Pension Cost	7,280	6,743
Taxes Other than Income and Other	9,411	5,607
	$18,380	$13,847

/(1)/ In 2001, primarily represents cash in escrow for assumed Cody Company liabilities.

4. Inventories

Inventories are comprised of the following:

(In thousands)	December 31, 2001	2000
Natural Gas and Oil in Storage	$12,622	$10,277
Tubular Goods and Well Equipment	4,059	2,122
Pipeline Exchange Balances	879	(1,362)
	$17,560	$11,037

5. Debt and Credit Agreements

10.18% Notes

In May 1990, the Company issued an aggregate principal amount of $80 million of its 12-year 10.18% Notes (10.18% Notes) to a group of nine institutional investors in a private placement offering. The 10.18% Notes require five annual $16 million principal payments each May starting in 1998. The fourth payment due in May 2001, classified as Current Portion of Long-Term Debt, was a current liability on the Company's Consolidated Balance Sheet at December 31, 2000. However, the Company prepaid the remaining $32 million in May 2001 along with a $0.9 million prepayment penalty, which was recorded as a component of interest expense.

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7.19% Notes

In November 1997, the Company issued an aggregate principal amount of $100 million of its 12-year 7.19% Notes (7.19% Notes) to a group of six institutional investors in a private placement offering. The 7.19% Notes require five annual $20 million principal payments starting in November 2005. The Company may prepay all or any portion of the indebtedness on any date with a prepayment penalty. The 7.19% Notes contain restrictions on the merger of the Company or any subsidiary with a third party other than under certain limited conditions. There are also various other restrictive covenants customarily found in such debt instruments. These covenants include a required asset coverage ratio (present value of proved reserves to debt and other liabilities) that must be at least 1.5 to 1.0, and a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0.

7.33% Weighted Average Fixed Rate Notes

To partially fund the cash portion of the acquisition of Cody Company in August 2001, the Company issued $170 million of Notes to a group of seven institutional investors in a private placement transaction in July 2001. Prior to the determination of the Note's interest rates, the Company entered into a treasury lock in order to reduce the risk of rising interest rates. Interest rates rose during the pricing period, resulting in a $0.7 million gain that will be amortized over the life of the Notes, and thereby reducing the effective interest rate by 5.5 basis points. All of the Notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Coupon
Tranche 1	$75,000,000	10-year	7.26%
Tranche 2	$75,000,000	12-year	7.36%
Tranche 3	$20,000,000	15-year	7.46%

The Notes were issued under the same Note Purchase Agreement as the 7.19% Notes.

Revolving Credit Agreement

The Company has a $250 million Revolving Credit Agreement (Credit Facility) that utilizes nine banks. The term of the Credit Facility expires on December 17, 2003. The available credit line is subject to adjustment from time-to-time on the basis of the projected present value (as determined by the banks' petroleum engineer) of estimated future net cash flows from certain proved oil and gas reserves and other assets of the Company. While the Company does not expect a change in the available credit line, in the event that it is adjusted below the outstanding level of borrowings, the Company has a period of 180 days to reduce its outstanding debt to the adjusted credit line. The Credit Facility also includes a requirement to pay down half of the debt in excess of the adjusted credit line within the first 90 days of such an adjustment.

Interest rates are principally based on a reference rate of either the rate for certificates of deposit (CD rate) or LIBOR, plus a margin, or the prime rate. For CD rate and LIBOR borrowings, interest rates are subject to increase if the total indebtedness is either greater than 60% or 80% of the Company's debt limit of $520 million, as shown below.

	Debt Percentage		
	Lower than 60%	60% - 80%	Higher than 80%
LIBOR margin	0.750%	1.000%	1.250%
CD margin	0.875%	1.125%	1.375%
Commitment fee rate	0.250%	0.375%	0.375%

The Credit Facility provides for a commitment fee on the unused available balance at an annual rate one-fourth of 1% or three-eighths of 1% depending on the level of indebtedness as indicated above. The Company's effective interest rates for the Credit Facility in the years ended December 31, 2001, 2000 and 1999 were 7.6%, 7.8%, and 6.7%, respectively. The Credit Facility contains various customary restrictions, which include the following:

(a) Prohibition of the merger of the Company or any subsidiary with a third party except under certain limited conditions.
(b) Prohibition of the sale of all or substantially all of the Company's or any subsidiary's assets to a third party.
(c) Maintenance of a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0.

The Company was in compliance with all covenants at December 31, 2001 and 2000.

6. Employee Benefit Plans

Pension Plan

The Company has a non-contributory, defined benefit pension plan for all full-time employees. Plan benefits are based primarily on years of service and salary level near retirement. Plan assets are mainly fixed income investments and equity securities. The Company complies with the Employee Retirement Income Security Act of 1974 and Internal Revenue Code limitations when funding the plan.

The Company has a non-qualified equalization plan to ensure payments to certain executive officers of amounts to which they are already entitled under the provisions of the pension plan, but which are subject to limitations imposed by federal tax laws. This plan is unfunded.

Net periodic pension cost of the Company for the years ended December 31, 2001, 2000 and 1999 are comprised of the following:

(In thousands)	2001	2000	1999
Qualified			
Current Year Service Cost	$ 914	$ 832	$1,012
Interest Accrued on Pension Obligation	1,198	1,070	1,072
Expected Return on Plan Assets	(1,064)	(1,123)	(919)
Net Amortization and Deferral	88	88	88
Recognized Gain	(28)	(282)	--

Net Periodic Pension Cost	$ 1,108	$ 585	$1,253

(In thousands)	2001	2000	1999
Non-Qualified			
Current Year Service Cost	$ 88	$ 60	$ 140
Interest Accrued on Pension Obligation	72	42	67
Net Amortization	77	77	77
Recognized (Gain) Loss	21	(5)	35
Net Periodic Pension Cost	$ 258	$ 174	$ 319

The following table illustrates the funded status of the Company's pension plans at December 31, 2001, and 2000, respectively:

	2001		2000	
(In thousands)	Qualified	Non-Qualified	Qualified	Non-Qualif
Actuarial Present Value of:				
Accumulated Benefit Obligation	$14,279	$ 816	$12,188	$
Projected Benefit Obligation	$18,996	$ 898	$16,173	$
Plan Assets at Fair Value	9,909	--	11,801	
Projected Benefit Obligation in Excess of Plan Assets	9,087	898	4,372	
Unrecognized Net Gain (Loss)	(2,153)	(260)	1,956	(
Unrecognized Prior Service Cost	(511)	(553)	(599)	(
Adjustment to Recognize Minimum Liability	--	731	--	
Accrued Pension Cost	$ 6,423	$ 816	$ 5,729	$

The change in the combined projected benefit obligation of the Company's qualified and non-qualified pension plans during the last three years is explained as follows:

(In thousands)	2001	2000	1999
Beginning of Year	$17,151	$14,546	$16,449
Service Cost	1,002	892	1,152
Interest Cost	1,270	1,112	1,139
Actuarial Loss (Gain)	1,166	1,328	(3,657)
Benefits Paid	(695)	(727)	(537)
End of Year	$19,894	$17,151	$14,546

The change in the combined plan assets at fair value of the Company's qualified and non-qualified pension plans during the last three years is explained as follows:

(In thousands)	2001	2000	1999
Beginning of Year	$11,801	$12,092	$10,344
Actual Return on Plan Assets	(1,527)	(440)	2,428
Employer Contribution	584	1,172	101
Benefits Paid	(695)	(727)	(537)
Expenses Paid	(254)	(296)	(244)
End of Year	$ 9,909	$11,801	$12,092

The reconciliation of the combined funded status of the Company's qualified and non-qualified pension plans at the end of the last three years is explained as follows:

(In thousands)	2001	2000	1999
Funded Status	$ 9,985	$ 5,350	$ 2,454
Unrecognized Gain (Loss)	(2,413)	1,605	5,078
Unrecognized Prior Service Cost	(1,064)	(1,229)	(1,394)
Net Amount Recognized	$ 6,508	$ 5,726	$ 6,138
Accrued Benefit Liability - Qualified Plan	$ 6,423	$ 5,729	$ 6,194
Accrued Benefit Liability - Non-Qualified Plan	816	753	504
Intangible Asset	(731)	(756)	(560)
Net Amount Recognized	$ 6,508	$ 5,726	$ 6,138

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Assumptions used to determine projected post-retirement benefit obligations and pension costs are as follows:

	2001	2000	1999
Discount Rate /(1)/	7.25%	7.50%	7.75%
Rate of Increase in Compensation Levels	4.00%	4.00%	4.00%
Long-Term Rate of Return on Plan Assets	9.00%	9.00%	9.00%

/(1)/ Represents the rate used to determine the benefit obligation. A 7.50% discount rate was used to compute pension costs in 2001, a rate of 7.75% in 2000, and a rate of 7.0% was used in 1999.

Savings Investment Plan

The Company has a Savings Investment Plan (SIP) which is a defined contribution plan. The Company matches a portion of employees' contributions in cash. Participation in the SIP is voluntary and all regular employees of the Company are eligible to participate. The Company charged to expense plan contributions of $1.0 million, $0.7 million, and $0.7 million in 2001, 2000, and

1999, respectively. The plan contribution rose in 2001 due to an increase in the Company's matching program. Effective July 1, 2001, the Company increased its dollar-for-dollar matching limit from 4% to 6% of an employee's pretax earnings. The Company's Common Stock is an investment option within the SIP.

Deferred Compensation Plan

In 1998, the Company established a Deferred Compensation Plan. This plan is available to officers of the Company and acts as a supplement to the Savings Investment Plan. The Company matches a portion of the employee's contribution and those assets are invested in instruments selected by the employee. Unlike the SIP, the Deferred Compensation Plan does not have dollar limits on tax deferred contributions. However, the assets of this plan are held in a rabbi trust and are subject to additional risk of loss in the event of bankruptcy or insolvency of the Company. At December 31, 2001, the balance in the Deferred Compensation Plan's rabbi trust was $1.0 million.

The employee participants guide the diversification of trust assets. The trust assets are invested in 13 mutual funds that cover the investment spectrum from equity to money market. These mutual funds are publicly quoted and reported at market value. No shares of Cabot Oil & Gas stock are held by the trust. Settlement payments are made to participants in cash, either in a lump sum or in periodic installments. The market value of the trust assets is recorded on the Company's balance sheet as a component of "Other Assets" and the corresponding liability is recorded as a component of "Other Liabilities."

There is no impact on earnings or earnings per share from the changes in market value of the deferred compensation plan assets for two reasons. First, the changes in market value of the trust assets are offset completely by changes in the value of the liability, which represents trust assets belonging to plan participants. Second, no shares of Cabot Oil & Gas stock are held in the trust.

The Company charged to expense plan contributions of less than $20,000 in each year presented.

Postretirement Benefits Other than Pensions

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits for retired employees, including their spouses, eligible dependents and surviving spouses (retirees). These benefits are commonly called postretirement benefits. Most employees become eligible for these benefits if they meet certain age and service requirements at retirement. The Company was providing postretirement benefits to 240 retirees at the end of 2001 and 241 retirees at the end of 2000.

When the Company adopted SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," in 1992, it began amortizing the $16.9 million accumulated postretirement benefit, known as the Transition Obligation, over a period of 20 years.

Postretirement benefit costs recognized during the last three years are as follows:

(In thousands)	2001	2000	1999

Service Cost of Benefits Earned During the Year	$ 175	$ 187	$ 225
Interest Cost on the Accumulated Postretirement Benefit Obligation	388	534	515
Amortization Benefit of the Unrecognized Gain	(291)	(132)	(131)
Amortization Benefit of the Unrecognized Transition Obligation	662	662	690
Total Postretirement Benefit Cost	$ 934	$1,251	$1,299

The health care cost trend rate used to measure the expected cost in 2000 for medical benefits to retirees was 8%. Provisions of the plan should prevent further increases in employer cost after 2000.

A one-percentage-point increase or decrease in health care cost trend rates for future periods would not impact the accumulated net postretirement benefit obligation or the total postretirement benefit cost recognized. Company costs are capped at 2000 levels and the retirees assume any future increases in costs.

The funded status of the Company's postretirement benefit obligation at December 31, 2001, and 2000 is comprised of the following:

(In thousands)	2001
Plan Assets at Fair Value	$ --
Accumulated Postretirement Benefits Other Than Pensions	5,507
Unrecognized Cumulative Net Gain	3,292
Unrecognized Transition Obligation	(6,617)
Accrued Postretirement Benefit Liability	$ 2,182

The change in the accumulated postretirement benefit obligation during the last three years is presented as follows:

(In thousands)	2001	2000	1999
Beginning of Year	$5,429	$ 7,243	$ 7,693
Service Cost	175	187	225
Interest Cost	388	534	515
Amendments	--	--	(253)
Actuarial Loss (Gain)	265	(1,923)	(102)
Benefits Paid	(750)	(612)	(835)
End of Year	$5,507	$ 5,429	$ 7,243

7. Income Taxes

Income tax expense is summarized as follows:

(In thousands)	Year Ended December 31, 2001	2000	1999
Current			
Federal	$10,984 /(1)/	$ 3,089/(2)/	$(3,899)
State	496	216	--
Total	11,480	3,305	(3,899)
Deferred			
Federal	13,723	11,804	8,910
State	2,262	1,358	150
Total	15,985	13,162	9,060
Total Income Tax Expense	$27,465	$16,467	$ 5,161

/(1)/ The Federal Income Taxes Payable is zero at December 31, 2001 primarily as a result of tax payments made during the year, a 2000 overpayment applied to 2001, and a $1.8 million tax benefit related to stock option exercises during 2001.

/(2)/ The Federal Income Taxes Payable is zero at December 31, 2000 primarily as a result of tax payments made during the year and a $1.8 million tax benefit related to stock option exercises during 2000.

In the table above, the $4.5 million refund received in 1999 that applied to a net operating loss carryback to 1997 is reflected in "Current -Federal."

Total income taxes were different than the amounts computed by applying the statutory federal income tax rate as follows:

(In thousands)	Year Ended December 31, 2001	2000	1999
Statutory Federal Income Tax Rate	35%	35%	35%
Computed "Expected" Federal Income Tax	$ 26,092	$14,679	$4,788
State Income Tax, Net of Federal Income Tax	2,758	1,552	506
Other, Net	(1,385) /(1)/	236	(133)
Total Income Tax Expense	$ 27,465	$16,467	$5,161

/(1)/ Other, Net includes credit adjustments totaling $1.7 million to deferred taxes as a result of a reduction to the state effective tax rate.

The tax effects of temporary differences that resulted in significant portions of the deferred tax liabilities and deferred tax assets as of December 31, 2001, and 2000 were as follows:

(In thousands)	2001	2000
Deferred Tax Liabilities		
Property, Plant and Equipment	$224,031	$142,935
Deferred Tax Assets		
Alternative Minimum Tax Credit Carryforwards	4,943	5,817
Net Operating Loss Carryforwards	1,715	13,904
Note Receivable on Section 29 Monetization/ (1)/	4,928	6,397
Items Accrued for Financial Reporting Purposes	11,586	8,643
	23,172	34,761
Net Deferred Tax Liabilities	$200,859	$108,174

/(1)/ As a result of the monetization of Section 29 tax credits in 1996 and 1995, the Company recorded an asset sale for tax purposes in exchange for a long-term note receivable which will be repaid through 100% working and royalty interest in the production from the sold properties.

As of December 31, 2001, the Company had a net operating loss carryforward of $1.7 million for state income tax reporting purposes and none available for regular federal income tax purposes. The Company has alternative minimum tax credit carryforwards of $4.9 million which do not expire and can be used to offset regular income taxes in future years to the extent that regular income taxes exceed the alternative minimum tax in any such year.

8. Commitments and Contingencies

Lease Commitments

The Company leases certain transportation vehicles, warehouse facilities, office space, and machinery and equipment under cancelable and non-cancelable leases. Leases for the Company's offices in Houston and Denver each run for approximately eight more years. With the acquisition of Cody Company in August 2001, the Company assumed certain lease agreements, most of which expire in 2004. Most of the other leases expire within five years and may be renewed. Rent expense under such arrangements totaled $7.7 million, $6.3 million, and $5.0 million for the years ended December 31, 2001, 2000, and 1999, respectively.

Future minimum rental commitments under non-cancelable leases in effect at

December 31, 2001 are as follows:

(In thousands)	
2002	$ 5,194
2003	4,602
2004	3,953
2005	3,855
2006	3,619
Thereafter	8,620
	$29,843

Minimum rental commitments are not reduced by minimum sublease rental income of $0.3 million due in the future under non-cancelable subleases.

Contingencies

The Company is a defendant in various lawsuits and is involved in other gas contract issues. All known liabilities are fully accrued based on management's best estimate of the potential loss. In management's opinion, final judgments or settlements, if any, which may be awarded in connection with any one or more of these suits and claims would not have a significant impact on the results of operations, financial position or cash flows of any

period.

Environmental Liability

The EPA notified the Company in February 2000 of its potential liability for waste material disposed of at the Casmalia Superfund Site ("Site"), located on a 252-acre parcel in Santa Barbara County, California. Over 10,000 separate parties disposed of waste at the Site while it was operational from 1973 to 1992. The EPA stated that federal, state and local governmental agencies along with the numerous private entities that used the Site for disposal of approximately 4.5 billion pounds of waste would be expected to pay the clean-up costs, which are estimated by the EPA to be $271.9 million. The EPA is also pursuing the owners/operators of the Site to pay for remediation.

Documents received by the Company with the notification from the EPA indicate that the Company used the Site principally to dispose of salt water from two wells over a period from 1976 to 1979. There is no allegation that the Company violated any laws in the disposal of material at the Site. The EPA's actions stem from the fact that the owners/operators of the Site do not have the financial means to implement a closure plan for the Site.

A group of potentially responsible parties, including the Company, formed a group, called the Casmalia Negotiating Committee ("CNC"). The CNC has had extensive settlement discussions with the EPA and has reached a settlement in principal to pay approximately $27 million toward Site clean up in return for a release from liability. The CNC is currently negotiating a consent decree to memorialize the settlement. On January 30, 2002, the Company placed $1,283,283 in an escrow account. This amount approximates the Company's volumetric share of EPA's cost estimate, plus a 5% premium and is the Company's settlement amount. The escrow account is being funded by the Company and many other CNC members to maximize the likelihood that there will be sufficient funds to fund the settlement agreement upon its completion, which is expected later in 2002. This cash settlement, once released from escrow and paid to the federal government, will resolve all federal claims against the Company for response costs and will release the Company from all response costs related to the Site, except for future claims against the Company for natural resource damage, unknown conditions, transshipment risks and claims by third parties, all of which are expected to be covered by insurance to be purchased by participating CNC members. Responsibility for certain State of California oversight and response costs, while not covered by the settlement or insurance, are not expected to be material. No determination has been made as to whether any insurance arrangement will allow the Company to recover its contribution to the settlement.

The Company has established a reserve that management believes to be adequate to provide for this environmental liability based on its estimate of the probable outcome of this matter and estimated legal costs.

Wyoming Royalty Litigation

In June 2000, two overriding royalty owners sued the Company in Wyoming State court for unspecified damages. The plaintiffs have requested class certification under the Wyoming Rules of Civil Procedure and allege that the Company has deducted improper costs of production from royalty payments to the plaintiffs and other similarly situated persons. Additionally, the suit claims that the Company has failed to properly inform the plaintiffs and other similarly situated persons of the deductions taken from royalties. In December 2001, fourteen overriding royalty owners sued the Company in Wyoming federal court. The plaintiffs in the federal case have made the same general claims pertaining to deductions from their overriding royalty as the plaintiffs in the Wyoming state court case but have not asked for class certification.

The Company believes that it has substantial defenses to these claims and intends to vigorously assert such defenses. The Company has a reserve that it believes is adequate to provide for these potential liabilities based on its estimate of the probable outcome of this matter. While the potential impact to the Company may materially affect quarterly or annual financial results including cash flows, management does not believe it would materially impact the Company's financial position.

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West Virginia Royalty Litigation

In late December 2001, two royalty owners sued the Company in West Virginia State court for an unspecified amount of damages. The plaintiffs have requested class certification under the West Virginia Rules of Civil Procedure and allege that the Company has failed to pay royalty based upon the wholesale market value of the gas produced, that the Company has taken improper deductions from the royalty and that the Company has failed to properly inform the plaintiffs and other similarly situated persons of deductions taken from the royalty.

Although the investigation into this claim has just begun, the Company intends to vigorously defend the case. Management cannot currently determine the likelihood or range of any potential outcome.

9. Cash Flow Information

Cash paid for interest and income taxes is as follows:

Year Ended December 31,

(In thousands)	2001	2000	1999
Interest	$16,295	$23,180	$25,445
Income Taxes	$14,395	$ 1,419	$ 652

At December 31, 2001, and 2000, the Accounts Payable balance on the Consolidated Balance Sheet included payables for capital expenditures of $30.9 million and $13.5 million, respectively.

10. Capital Stock

Incentive Plans

On May 3, 2001, the Second Amended and Restated 1994 Long-Term Incentive Plan and the Second Amended and Restated 1994 Non-Employee Director Stock Option Plan were approved by the shareholders. The Company has two other stock option plans: the 1990 Incentive Stock Option Plan and the 1990 Non-Employee Director Stock Option Plan. Under these four plans (Incentive Plans), incentive and non-statutory stock options, stock appreciation rights (SARs) and stock awards may be granted to key employees and officers of the Company, and non-statutory stock options may be granted to non-employee directors of the Company. A maximum of 5,260,000 shares of Common Stock may be issued under the Incentive Plans. All stock options have a maximum term of five or 10 years from the date of grant, with most vesting over time. The options are issued at market value on the date of grant. The minimum exercise period for stock options is six months from the date of grant. No SARs have been granted under the Incentive Plans.

Information regarding the Company's Incentive Plans is summarized below:

	December 31, 2001	2000	1999
Shares Under Option at Beginning of Period	1,124,148	1,773,389	1,557,936
Granted	454,100	299,250	454,100
Exercised	408,949	896,081	55,032
Surrendered or Expired	87,678	52,410	183,615
Shares Under Option at End of Period	1,081,621	1,124,148	1,773,389
Options Exercisable at End of Period	355,778	474,599	1,108,637

For each of the three most recent years, the price range for outstanding options was $14.69 to $27.30 per share. The following tables provide more information about the options by exercise price and year.

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Options with exercise prices between $14.69 and $20.00 per share:

	Decembe	
	2001	200

Options Outstanding		
Number of Options	480,561	866,
Weighted Average Exercise Price	$ 17.79	$ 17
Weighted Average Contractual Term (in years)	1.50	2
Options Exercisable		
Number of Options	211,734	372,
Weighted Average Exercise Price	$ 17.29	$ 16

Options with exercise prices between $20.01 and $27.30 per share:

		Decembe
	2001	200
Options Outstanding		
Number of Options	601,060	257,
Weighted Average Exercise Price	$ 25.44	$ 22
Weighted Average Contractual Term (in years)	4.30	1
Options Exercisable		
Number of Options	144,044	102,
Weighted Average Exercise Price	$ 22.45	$ 22

Under the Second Amended and Restated 1994 Long-Term Incentive Plan, the Compensation Sub-Committee of the Board of Directors may grant awards of performance shares of stock to members of the executive management group. Each grant of performance shares has a three-year performance period, measured as the change from July 1 of the initial year of the performance period to June 30 of the third year. The number of shares of Common Stock received at the end of the performance period is based mainly on the relative stock price growth between the two measurement dates of Common Stock compared to that of a group of peer companies. The performance shares granted in July 1996 were converted to 19,090 shares of the Company's Common Stock in 1999. The Board of Directors has not issued performance shares since July 1996, and currently, there are no performance shares outstanding.

Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation," outlines a fair value based method of accounting for stock options or similar equity instruments. The Company has opted to continue using the intrinsic value based method, as recommended by Accounting Principles Board (APB) Opinion No. 25, to measure compensation cost for its stock option plans.

If the Company had adopted SFAS 123, the pro forma results of operations would be as follows:

	2001	2000
Net Income/(1)/	$45.7 million	$28.2 million
Net Income per Share	$1.51	$1.03
Weighted Average Value of		
Options Granted During the Year/(2)/	$8.61	$6.63
Assumptions		
Stock Price Volatility	34.9%	34.5%

Risk Free Rate of Return	4.7%	5.21%
Dividend Rate (per year)	$0.16	$0.16
Expected Term (in years)	4	4

/(1)/ Net income is defined as Net Income Available to Common Shareholders.
/(2)/ Calculated using the fair value based method.

The fair value of stock options included in the pro forma results for each of the three years is not necessarily indicative of future effects on net income and earnings per share.

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Dividend Restrictions

The Board of Directors of the Company determines the amount of future cash dividends, if any, to be declared and paid on the Common Stock depending on, among other things, the Company's financial condition, funds from operations, the level of its capital and exploration expenditures, and its future business prospects. None of the note or credit agreements in place have a restricted payment provision.

Treasury Stock

In August 1998, the Board of Directors authorized the Company to repurchase up to two million shares of outstanding Common Stock at market prices. The timing and amount of these stock purchases are determined at the discretion of management. The Company may use the repurchased shares to fund stock compensation programs presently in existence, or for other corporate purposes. As of December 31, 1998, the Company had repurchased 302,600 shares, or 15% of the total authorized number of shares, for a total cost of approximately $4.4 million. No additional shares were repurchased during 1999, 2000 or 2001. The stock repurchase plan was funded from increased borrowings on the revolving credit facility. No treasury shares were delivered or sold by the Company during the year.

Purchase Rights

On January 21, 1991, the Board of Directors adopted the Preferred Stock Purchase Rights Plan and declared a dividend distribution of one right for each outstanding share of Common Stock. On December 8, 2000, the rights agreement for the plan was amended and restated to extend the term of the plan to 2010 and to make other changes. Each right becomes exercisable, at a price of $55, when any person or group has acquired or made a tender or exchange offer for beneficial ownership of 15 percent or more of the Company's outstanding Common Stock. Each right entitles the holder, other than the acquiring person or group, to purchase one one-hundredth of a share of Series A Junior Participating Preferred Stock (Junior Preferred Stock). After a person or group acquires beneficial ownership of 15% of the Common Stock, each right entitles the holder to purchase Common Stock or other property having a market value (as defined in the plan) of twice the exercise price of the right. An exception to this triggering event applies in the case of a tender or exchange offer for all outstanding shares of Common Stock determined to be fair and in the best interests of the Company and its stockholders by a majority of the independent directors. Under certain circumstances, the Board of Directors may opt to exchange one share of Common Stock for each exercisable right. If there is a 15% holder and the Company is acquired in a merger or other business combination in which it is not the survivor, or 50 percent or more of the Company's assets or earning power are sold or transferred, each right entitles the holder to purchase common stock of the acquiring company with a market value (as defined in the plan) equal to twice the exercise price of each right. At December 31, 2001, and 2000, there were no shares of Junior Preferred Stock issued or outstanding.

The rights expire on January 21, 2010, and may be redeemed by the Company for $0.01 per right at any time before a person or group acquires beneficial ownership of 15% of the Common Stock.

Preferred Stock

At December 31, 1999 and 1998, 1,134,000 shares of 6% convertible redeemable preferred stock (6% preferred stock) were issued and outstanding. The shares of 6% preferred stock were issued in May 1994 to the seller in connection with Cabot Oil & Gas' acquisition of a subsidiary of the seller. The 6% preferred stock had a liquidation preference of $50 per share, provided for quarterly cash dividends at the rate of 6% per annum, was convertible into Cabot Oil & Gas Class A common stock at the holder's option at a conversion price of $28.75, and was entitled to 1.739 votes per share, generally voting together with the Class A common stock. The 6% preferred stock was not redeemable at the holder's option, but was redeemable at the option of Cabot Oil & Gas commencing in May 1998 at a price of $50 per share, payable in shares of Class A common stock until May 1999 and in cash thereafter, plus cash in an amount equal to accrued and unpaid dividends.

In October 1999, Cabot Oil & Gas agreed with the holder of the 6% preferred stock that the Company would repurchase all the 6% preferred stock for $51.6 million in cash or Class A common stock. During the second

quarter of 2000, the Company completed this repurchase and paid the holder of the preferred stock $51.6 million in cash. The cash payment was funded using a portion of the proceeds from the issuance of 3,400,000 shares of Class A common stock in a registered offering at a price of $21.50 per share (yielding net proceeds of $71.5 million, after expenses). The remaining proceeds of this offering of Class A common stock were used to reduce borrowings under the revolving credit facility.

The difference between the payment to the holder of the 6% preferred stock ($51.6 million) and the carrying amount of the 6% preferred stock on the Company's balance sheet ($56.7 million) was added to net earnings available to common shareholders in the calculation of earnings per share. This difference represents a forgone return to the preferred shareholder and is treated similar to a dividend; accordingly, a negative dividend of $5.1 million was recognized upon the repurchase.

11. Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the consolidated balance sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value. The Company uses available marketing data and valuation methodologies to estimate fair value of debt.

Long-Term Debt

	December 31, 2001		December 31, 2000	
	Carrying	Estimated	Carrying	Estimated

(In thousands)	Amount	Fair Value	Amount	Fair Value
Debt				
10.18% Notes	$ --	$ --	$ 32,000	$ 33,162
7.19% Notes	100,000	104,961	100,000	97,033
7.26% Notes	75,000	79,187	--	--
7.36% Notes	75,000	79,225	--	--
7.46% Notes	20,000	21,097	--	--
Credit Facility	123,000	123,000	137,000	137,000
	$393,000	$407,470	$269,000	$267,195

The fair value of long-term debt is the estimated cost to acquire the debt, including a premium or discount for the difference between the issue rate and the year-end market rate. The fair value of the 10.18% Notes, the 7.19% Notes, the 7.26% Notes, the 7.36% Notes and the 7.46% Notes is based on interest rates currently available to the Company. The 10.18% Notes were repaid in May 2001. The Credit Facility approximates fair value because this instrument bears interest at rates based on current market rates.

Commodity Price Swaps and Options

Hedges on Production - Swaps

From time to time, the Company enters into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of its production. These derivatives are not held for trading purposes. Under these price swaps, the Company receives a fixed price on a notional quantity of natural gas and crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures. During 2001, the Company fixed the price at an average of $3.75 per Mcf on quantities totaling 918 Mmcf, representing 1% of the Company's 2001 natural gas production. The Company did not have crude oil swap arrangements covering its production in 2001. During 2000, the Company fixed the price at an average of $4.54 per Mcf on quantities totaling 315 Mmcf, representing less than 1% of the Company's 2000 natural gas production. The notional volume of the crude oil swap transactions was 364 Mbbls at a price of $22.67 per Bbl, which represents approximately 38% of the Company's total oil production for 2000. During 1999, the Company fixed the price at an average of $2.88 per Mcf on quantities totaling 3,237 Mmcf, representing 5% of the Company's 1999 natural gas production. The notional volume of the crude oil swap transactions was 306 Mbbls at a price of $20.65 per Bbl, which represents approximately one-third of the Company's total oil production for 1999.

The natural gas price swap arrangement that the Company entered into during the third quarter of 2000 covered a portion of production over the period of October 2000 through September 2003. However, the counterparty declared bankruptcy in December 2001. Based on the terms of the natural gas swap contract, this action results in the cancellation of the contract. As of the years ending December 31, 2001, and 2000, the Company had open natural gas price swap contracts on its production as follows:

Natural Gas Price Swaps		
Volume in	Weighted Average	Unrealized Gain/(Loss)

Contract Period	Mmcf	Contract Price	(in $ millions)
As of December 31, 2001			
None			
As of December 31, 2000			
Natural Gas Price Swaps on Production in:			
Full Year 2001	918	$3.75	$(2.8)
Full Year 2002	678	3.11	(1.0)
Full Year 2003	423	2.81	(0.5)

Financial derivatives related to natural gas production reduced revenues by $0.8 million in 2001 and $0.3 million in 2000.

The Company had no open oil price swap contracts outstanding on its production at December 31/st/ of 2001 or 2000. Financial derivatives related to crude oil reduced revenue by $2.2 million during 2000, but had no impact on 2001 results.

Hedges on Production - Options

In December 2000, management believed that the pricing environment provided a strategic opportunity to significantly reduce the price risk on a portion of the Company's production through the use of costless collars. Under the costless collar arrangements, if the index rises above the ceiling price, the Company pays the counterparty. If the applicable index falls below the floor, the counterparty pays the Company. The natural gas price hedges include several costless collar arrangements based on eight price indexes at which the Company sells a portion of its production. These hedges were in place for the months of February through October 2001 and covered 24,404 Mmcf, or 35%, of the Company's natural gas production for the year. All indexes were within the collars during February and April, some fell below the floor during the period of March, and all indexes were below the floor from June through October, resulting in $34.6 million cash revenue for the year. This revenue contributed $0.50 per Mcf to the Company's average realized natural gas price for 2001.

During 2000, the Company used several costless collar arrangements to hedge a portion of its natural gas production. There were seven collar arrangements based on separate regional price indexes with a weighted average price floor of $2.74 per Mcf and a weighted average price ceiling of $3.38 per Mcf. These collars were in place during the months of April through October 2000. These collars covered a total quantity of 9,909 Mmcf, or 16% of the Company's annual production. In April and May 2000, the index prices all fell within the price collar and no settlements were made. In June 2000, all of the indexes rose above the ceiling prices and remained above the ceiling for the duration of the transaction resulting in a $10 million reduction to the Company's realized revenue for the year. If these hedges had not been in place, the Company's average realized natural gas price for 2000 would have been $0.17 per Mcf higher.

Again in December of 2001, management believed that the pricing environment provided a strategic opportunity to significantly reduce the price risk on a portion of the Company's future production through the use of natural gas price collar arrangements. A premium totaling $0.9 million was paid to purchase these collar arrangements. This cost will be expensed as the instruments are marked-to-market each quarter. As of December 31, 2001, the Company had open natural gas price collar arrangements to hedge production as follows:

Contract Period	Natural Gas Price Collars Volume in Mmcf	Weighted Average Ceiling / Floor	Unreali Gain/(L (in $ mil
As of December 31, 2001			
Natural Gas Collars on Production in:			
First Quarter of 2002	12,082	$3.54/$2.68	
Second Quarter of 2002	4,027	$3.54/$2.68	
As of December 31, 2000			
Natural Gas Costless Collars on Production in:			
First Quarter of 2001	5,274	$9.68/$5.59	
Second Quarter of 2001	8,135	$9.68/$5.59	
Third Quarter of 2001	8,224	$9.68/$5.59	
Fourth Quarter of 2001	2,771	$9.68/$5.59	

The natural gas price hedges open at December 31, 2001, noted above, include several collar arrangements based on nine price indexes at which the Company sells a portion of its production. These hedges are in place for the months of January through April 2002 and cover approximately 60% of the Company's anticipated natural gas production during this period. A premium totaling $0.9 million was paid to purchase these collar arrangements.

Hedges on Brokered Transactions

The Company uses price swaps to hedge the natural gas price risk on brokered transactions. Typically, the Company enters into contracts to broker natural gas at a variable price based on the market index price. However, in some circumstances, some of the customers or suppliers request that a fixed price be stated in the contract. After entering into these fixed price contracts to meet the needs of the customers or suppliers, the Company may use price swaps to effectively convert these fixed price contracts to market-sensitive price contracts. These price swaps were held by the Company to their maturity and are not held for trading purposes.

The Company entered into price swaps with total notional quantities of 1,295 Mmcf in 2000, and 3,572 Mmcf in 1999 related to its brokered activities, representing 3% and 7% respectively, of its total volume of brokered natural gas sold. The Company did not use price swaps on brokered transactions in 2001.

As of the years ending December 31, 2000 and 2001, the Company had no open natural gas price swap contracts on brokered transactions. Financial derivatives related to natural gas reduced revenues by less than $0.1 million in 2000 and had no impact on revenue in 2001.

The Company is exposed to market risk on these open contracts, to the extent of changes in market prices of natural gas and oil. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged.

Adoption of SFAS 133

The Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) on January 1, 2001. Under SFAS 133, the fair value of each derivative instrument is recorded as either an asset or liability on the balance sheet. At the end of each period, these instruments are marked-to-market. The gain or loss on the change in fair value is recorded as Other Comprehensive Income, a component of equity, to the extent that the derivative instrument is an effective hedge. Under SFAS 133, effectiveness is a measurement of how closely correlated the hedge instrument is with the underlying physical sale. For example, a natural gas price swap that converts Henry Hub index to a fixed price would be perfectly correlated, and 100% effective, if the underlying gas was sold at the Henry Hub index. Any portion of the gains or losses that are considered ineffective under the SFAS 133 test are recorded immediately as a component of operating revenue on the statement of operations.

When the Company adopted SFAS 133, two types of hedges were in place. The first type was a cash flow hedge that sets the price of a certain monthly quantity of natural gas sold in the Gulf Coast region through September

2003. Based on the index price strip, the impact of this hedge on January 1, 2001 was to record a Hedge Loss of $0.1 million and a charge to Other Comprehensive Income of $4.2 million. Correspondingly, a Hedge Liability for $4.3 million was established. This instrument was cancelled in the December 2001 with the bankruptcy of the counterparty. No balance related to this hedge remains in Other Comprehensive Income.

The second type of hedge outstanding at January 1, 2001 was a natural gas price costless collar agreement. The Company had entered into eight of these collars for a portion of its production at regional indexes for the months of February through October 2001. The collars had two components of value: intrinsic value and time value. Under SFAS 133, both components were valued at the end of each reporting period. Intrinsic value arises when the index price is either above the ceiling or below the floor for any period covered by the collar. If the index is above the ceiling for any month covered by the collar, the intrinsic value would be the difference between the index and the ceiling prices multiplied by the notional volume. Similar to the current accounting treatment, intrinsic value related to the current month would be recorded as a hedge loss (if the index is above the ceiling) or gain (if the index is below the floor). Starting in 2001 under SFAS 133, any changes in the intrinsic value component related to future months were recorded in Other Comprehensive Income, a component of stockholders' equity on the balance sheet, rather than to the income statement to the extent that the hedge was proven to be effective. These natural gas price collars were considered to be highly effective with respect to the intrinsic value calculation since they were tied to the same indexes at which the Company's natural gas is sold. Also under SFAS 133, the time value component, a market premium/discount, was marked-to-market through the income statement each period. Since these collar arrangements were executed on the last business day of 2000, the net premium value at adoption on January 1, 2001 was zero.

As of December 31, 2001, the Company had a series of nine natural gas price collar arrangements in place. In accordance with the latest guidance from the FASB's Derivative Implementation Group, the Company determines the effectiveness of the combined intrinsic and time values, and the effective portion of each will be recorded as a component of Other Comprehensive Income. Any ineffective portion will be recorded as a gain or loss in the current period. As of December 31, 2001, the Company had recorded $1.4 million of Other Comprehensive Income

($0.8 million net of deferred taxes), a $0.1 million Unrealized Hedge Gain and a $1.5 million Hedge Asset.

Other Comprehensive Income

Comprehensive income includes net income and certain items recorded directly to stockholders' equity and classified as Other Comprehensive Income. The Company recorded Other Comprehensive Income for the first time in January of 2001. Following the adoption of SFAS 133, the Company recorded an after-tax credit to Other Comprehensive Income of $0.8 million in 2001 related to the change in fair value of certain derivative financial instruments that has qualified for cash flow hedge accounting.

Credit Risk

Although notional contract amounts are used to express the volume of natural gas price agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. The Company does not anticipate any material impact on its financial results due to non-performance by the third parties. The Company had no sales to any customer that exceeded 10% of total gross revenues in 2001, 2000 or 1999.

12. Oil and Gas Property Transactions

In September and December 1999, the Company purchased oil and gas producing properties in the Moxa Arch of the Green River Basin in southwest Wyoming for $8.9 and $8.5 million, respectively. The assets included approximately 16 Bcfe of proved reserves, approximately 43,000 undeveloped net acres, and 27 wells producing a net 3.8 Mmcfe per day at the time of the acquisition.

Also in September 1999, the Company sold non-strategic oil and gas properties located in Pennsylvania and West Virginia to EnerVest for approximately $46 million. These properties represented 716 wells and 62.2 Bcfe of proved reserves.

The property transactions in September and December 1999 qualified in part for Section 1031 exchange treatment for tax purposes. This treatment resulted in the $8.9 million deferred gain for tax purposes. For tax purposes, the assets acquired in the exchange were recorded at the value (tax basis) of the assets given up. The "gain" is deferred and recognized through lower tax depreciation on these assets and/or by inclusion in the taxable gain/loss calculation should these assets be subsequently sold.

For financial statement purposes, these transactions were treated as a purchase and a sale, as opposed to a deferred transaction. The asset sale resulted in a $4.1 million gain for financial statement purposes, which was recorded in September 1999.

In the second quarter of 1999, the Company sold certain non-strategic properties in the Gulf Coast region's Provident City field. These properties were producing 3.5 Mmcfe per day from eight wells. The sales price was $9.1 million, and the transaction contributed to a gain of approximately $1.0 million on the Company's second quarter income statement.

13. Other Revenue

Settlement of Contract Dispute

During 2000, the Company reached settlement on a natural gas contract dispute. As a result, the Company recorded net revenue of approximately $2.3 million to Other Revenue during 2000.

The dispute involved a contract under which the customer was obligated to take-or-pay a daily base quantity of natural gas over a 10-year period ending in 2003. The customer also agreed to pay a reservation charge in exchange for the right to purchase optional quantities of natural gas from the Company. The sales price of the natural gas sold under this contract increased over time.

In 1997, the customer's parent company decided to close the facility that was purchasing the gas from the Company. The Company agreed to market the gas that had been committed to the customer and the customer agreed to pay the difference between the price the Company received and an agreed upon price until December 31, 1998. Starting on January 1, 1999, the customer again became responsible for purchasing the gas under the original contract terms. The Company invoiced the customer for the contractual sales quantities during 1999, but received no payment. The unpaid balance was included in accounts receivable.

When the Company reached the contract settlement with this customer in the first quarter of 2000, a portion of the settlement was used to satisfy the accounts receivable account. The remainder represented a contract buy-out and was recorded in Other Revenue. No reserve had been recorded for this dispute.

Sales Contract

The Company had a 15-year natural gas sales contract under which approximately 20% of the Western region natural gas was sold per year to an independent third-party cogeneration facility. The contract was a standard long-term, natural gas sales contract under which the Company sold gas to the facility for a fixed price, which escalated annually. Revenue from the sale of natural gas is included in "Natural Gas Production" on the Consolidated Statement of Operations. The contract was due to expire in 2008. The customer requested to be released from the contract, and during 1999, the Company reached an agreement with the customer under which the

customer bought out the remainder of the contract for a $12 million cash payment to the Company in exchange for a release from future obligations under the contract. This transaction was completed in December 1999, and the $12 million payment was recorded as other revenue. Simultaneously, the Company sold forward a similar monthly volume of Western region gas through April 2001 at prices similar to those in the monetized contract.

Section 29 Tax Credits

Other revenue includes income generated from the monetization of the value of Section 29 tax credits (monetized credits) from most of the Company's qualifying Appalachian and Rocky Mountains properties. Revenue from these monetized credits was $2.0 million in 2001, $2.2 million in 2000, and $1.3 million in 1999. These monetized credits are expected to generate future revenues in 2002 of $2.1 million. The production, revenues, expenses and proved reserves for these properties will continue to be reported by the Company as Other Revenue until the production payment is satisfied.

During 1999, an industry tax court ruling concluded that the Section 29 tight sands tax credits (Section 29 credits) would not be available on wells not certified by the FERC. Because the FERC discontinued the certification process for qualifying wells in 1992, there was no avenue to obtain the well certifications. Accordingly, the Company stopped recording revenue on non-certified wells and established a reserve related to previously recorded amounts on these wells. This resulted in a $1.2 million reduction to other revenue in 1999. Subsequent to 1999, the certification process has been reinstated by FERC, and the Company has begun applying for the well certificates and accruing Section 29 credit revenues related to these wells.

14. Acquisition of Cody Company

Effective in August 2001, the Company acquired the stock of Cody Company, the parent of Cody Energy LLC ("Cody acquisition") for $231.2 million comprised of $181.3 million of cash and 1,999,993 shares of common stock valued at $49.9 million. Substantially all of the proved reserves of Cody Company are located in the onshore Gulf Coast region. The acquisition was accounted for using the purchase method of accounting. As such, the Company reflected the assets and liabilities acquired at fair value in the Company's balance sheet effective August 1, 2001 and the results of operations of Cody Company beginning August 1, 2001. The purchase price totaling approximately $315.6 million was allocated to specific assets and liabilities based on certain estimates of fair values resulting in approximately $302.4 million allocated to property and $13.2 million allocated to working capital items. This $315.6 million amount was inclusive of a $78.0 million non-cash item pertaining to the deferred income taxes attributable to the differences between the tax basis and the fair value of the acquired oil and gas properties, and acquisition related fees and costs of $6.4 million. The purchase price allocation is preliminary and subject to change as additional information becomes available. Management does not expect the final purchase price allocation to differ materially from the preliminary allocation.

The following unaudited pro forma condensed income statement information has been prepared to give effect to the Cody acquisition as if it had occurred on January 1, 2000. The information presented is not necessarily indicative of the results of future operations of the Company.

	Year Ended December 31,	
(In thousands)	2001	2000
Revenues	$505,528	$444,793
Net Income	$ 54,513	$ 25,997
per share - Basic	$ 1.75	$ 0.90
per share - Diluted	$ 1.73	$ 0.89

The results of operations for Cody Company are consolidated with Cabot Oil & Gas Corporation as of August 1, 2001.

15. Earnings per Common Share

Full year basic earnings per share for the Company were $1.56, $1.07, and $0.21 in 2001, 2000, and 1999, respectively, and were based on the weighted average shares outstanding of 30,275,906 in 2001, 27,383,848 in 2000, and 24,726,030 in 1999. Diluted earnings per share for the Company were $1.53, $1.06, and $0.21 in 2001, 2000, and 1999, respectively. The diluted earnings per share amounts are based on weighted average shares outstanding plus common stock equivalents. Common stock equivalents include stock awards and stock options, and totaled 408,361 in 2001, 281,210 in 2000, and 225,177 in 1999.

The 6% convertible redeemable preferred stock issued May 1994 had an antidilutive effect on earnings per common share. The preferred stock was determined not to be a common stock equivalent when it was issued. As such, no adjustments were made to net income in the computation of earnings per share for

1999. No preferred stock was outstanding at the end of 2000 or 2001. See Note 10 Capital Stock for further discussion.

CABOT OIL & GAS CORPORATION

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves represent estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made.

Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

Estimates of proved and proved developed reserves at December 31, 2001, 2000, and 1999 were based on studies performed by the Company's petroleum engineering staff. The estimates were reviewed by Miller and Lents, Ltd., who indicated in their letter dated February 8, 2002, that based on their investigation and subject to the limitations described in their letter, they believe the results of those estimates and projections were reasonable in the aggregate.

No major discovery or other favorable or unfavorable event after December 31, 2001, is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

The following table illustrates the Company's net proved reserves, including changes, and proved developed reserves for the periods indicated, as estimated by the Company's engineering staff.

	Natural Gas		
		December 31,	
(Millions of cubic feet)	2001	2000	1999
Proved Reserves			
Beginning of Year	959,222	929,602	996,756

Revisions of Prior Estimates	(44,266)	(14,796)	(1,555)
Extensions, Discoveries and Other Additions	99,911	103,600	52,781
Production	(69,162)	(60,934)	(65,502)
Purchases of Reserves in Place	91,290	5,118	26,515
Sales of Reserves in Place	(991)	(3,368)	(79,393)
End of Year	1,036,004	959,222	929,602
Proved Developed Reserves	804,646	754,962	720,670
Percentage of Reserves Developed	77.7%	78.7%	77.5%

	Liquids		
	December 31,		
(Thousands of barrels)	2001	2000	1999
Proved Reserves			
Beginning of Year	9,914	8,189	7,677
Revisions of Prior Estimates	254	562	128
Extensions, Discoveries and Other Additions	2,257	2,032	1,292
Production	(1,996)	(988)	(963)
Purchases of Reserves in Place	9,255	120	362
Sales of Reserves in Place	--	(1)	(307)
End of Year	19,684	9,914	8,189
Proved Developed Reserves	15,328	8,438	5,546
Percentage of Reserves Developed	77.9%	85.1%	67.7%

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to natural gas and crude oil producing activities and the total amount of related accumulated depreciation, depletion and amortization.

	Year Ended December 31,		
(In thousands)	2001	2000	1999
Aggregate Capitalized Costs Relating to Oil and Gas Producing Activities	$1,632,101	$1,180,692	$1,088,640
Aggregate Accumulated Depreciation, Depletion and Amortization	$ 651,657	$ 558,463	$ 499,201

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows:

(In thousands)	Year Ended December 31, 2001	2000	1999
Property Acquisition Costs, Proved /(1)/	$245,079	$ 5,954	$18,395
Property Acquisition Costs, Unproved /(1)/	21,116	10,869	7,163
Exploration and Extension Well Costs /(2)/	91,261	40,008	16,117
Development Costs	90,246	59,879	39,239
Total Costs	$447,702	$116,710	$80,914

/(1)/ Excludes the $78.0 million deferred tax gross-up on the Cody acquisition.
/(2)/ Includes administrative exploration costs of $9,831, $8,442, and $5,633 for the years ended December 31, 2001, 2000, and 1999, respectively. These costs are excluded from the Company's calculation of finding costs.

Historical Results of Operations from Oil and Gas Producing Activities

The results of operations for the Company's oil and gas producing activities were as follows:

(In thousands)	Year Ended December 31, 2001	2000	1999
Operating Revenues	$339,064	$214,116	$156,018
Costs and Expenses			
Production	58,382	46,721	41,942
Other Operating	22,656	17,249	17,009
Exploration /(1)/	71,165	19,858	11,490
Depreciation, Depletion and Amortization	89,286	63,200	62,446
Total Costs and Expenses	241,489	147,028	132,887
Income Before Income Taxes	97,575	67,088	23,131
Provision for Income Taxes	34,151	23,481	8,096
Results of Operations	$ 63,424	$ 43,607	$ 15,035

/(1)/ Includes administrative exploration costs of $9,831, $8,442, and $5,633 for the years ended December 31, 2001, 2000, and 1999, respectively. These costs are excluded from the Company's calculation of finding costs.

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

The following information has been developed utilizing SFAS 69 procedures and based on natural gas and crude oil reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- Future costs and selling prices will probably differ from those required to be used in these calculations.

- Due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations.

- Selection of a 10% discount rate is arbitrary and may not be a reasonable measure of the relative risk that is part of realizing future net oil and gas revenues.

- Future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows were estimated by applying year-end oil and gas prices adjusted for fixed and determinable escalations to the estimated future production of year-end proved reserves.

The average prices related to proved reserves at December 31, 2001, 2000, and 1999 for natural gas ($ per Mcf) were $2.65, $9.63, and $2.36, respectively, and for oil ($ per Bbl) were $18.56, $26.18, and $24.15, respectively. Future cash inflows were reduced by estimated future development and production costs based on year-end costs to arrive at net cash flow before tax. Future income tax expense was computed by applying year-end statutory tax rates to future pretax net cash flows, less the tax basis of the properties involved. SFAS 69 requires the use of a 10% discount rate.

Management does not use only the following information when making investment and operating decisions. These decisions are based on a number of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of anticipated economic conditions.

Standardized Measure is as follows:

(In thousands)	Year Ended December 31, 2001 /(1)/	2000 /(1)/	1999 /(1)/

Future Cash Inflows	$ 3,107,668	$ 9,497,181	$ 2,401,349
Future Production Costs	(823,988)	(1,435,489)	(622,025)
Future Development Costs	(266,833)	(192,893)	(164,377)
Future Net Cash Flows Before Income Taxes	2,016,847	7,868,799	1,614,947
10% Annual Discount for Estimated Timing of Cash Flows	(1,065,747)	(4,332,551)	(877,129)
Standardized Measure of Discounted Future Net Cash Flows Before Income Taxes	951,100	3,536,248	737,818
Future Income Tax Expenses, Net of 10% Annual Discount /(2)/	(185,074)	(1,126,416)	(150,261)
Standardized Measure of Discounted Future Net Cash Flows	$ 766,026	$ 2,409,832	$ 587,557

/(1)/ Includes the future cash inflows, production costs and development costs, as well as the tax basis, relating to the properties included in the transactions to monetize the value of Section 29 tax credits. See Note 13 of the Notes to the Consolidated Financial Statements.

/(2)/ Future income taxes before discount were $558,085, $2,642,810, and $457,256 for the years ended December 31, 2001, 2000 and 1999, respectively.

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

The following is an analysis of the changes in the Standardized Measure:

(In thousands)	Year Ended December 31, 2001	2000	1999
Beginning of Year	$ 2,409,832	$ 587,557	$ 594,078
Discoveries and Extensions, Net of Related Future Costs	100,084	486,236	65,210
Net Changes in Prices and Production Costs /(1)/	(2,545,349)	2,441,921	1,354
Accretion of Discount	353,625	73,782	73,893
Revisions of Previous Quantity Estimates, Timing and Other	(358,134)	(81,093)	(20,162)
Development Costs Incurred	26,158	28,540	19,586
Sales and Transfers, Net of Production Costs	(280,682)	(167,395)	(114,076)
Net Purchases (Sales) of Reserves in Place	119,149	16,440	(26,916)
Net Change in Income Taxes	941,343	(976,156)	(5,410)
End of Year	$ 766,026	$2,409,832	$ 587,557

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(1) For 2000, the prices for natural gas used in this calculation were regional cash price quotes on the last day of the year. These prices were higher than the Company actually realized in December 2000. Further, based on market conditions in February 2001, the prices are not indicative of those that the Company expects to realize

consistently in the future. For 2001, year-end pricing returned to the range that management considers typical.

CABOT OIL & GAS CORPORATION

SELECTED DATA (UNAUDITED)

QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

(In thousands, except per share amounts)	First	Second	Third	Fourth	Tot
2001					
Operating Revenues	$154,891	$107,606	$104,226	$ 80,319	$447
Impairment of Long-Lived Assets	--	--	1,721	5,131	6
Operating Income (Loss)	68,526	26,976	21,601	(21,737)	95
Net Income (Loss)	39,062	13,593	10,031	(15,602)	47
Basic Earnings per Share	$ 1.33	$ 0.46	$ 0.33	$ (0.49)	$
Diluted Earnings per Share	$ 1.32	$ 0.45	$ 0.32	$ (0.49)	$
2000					
Operating Revenues	$ 85,120	$ 82,447	$ 86,237	$114,847	$368
Impairment of Long-Lived Assets	--	9,143	--	--	9
Operating Income	14,773	420	15,799	33,825	64
Net Income	4,494	1,518	6,137	17,072	29
Basic Earnings per Share	$ 0.18	$ 0.05	$ 0.21	$ 0.59	$
Diluted Earnings per Share	$ 0.18	$ 0.05	$ 0.21	$ 0.58	$

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

The information under the caption "Election of Directors" in the Company's definitive Proxy Statement in connection with the 2001 annual stockholders' meeting is incorporated by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information under the caption "Executive Compensation" in the definitive Proxy Statement is incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information under the captions "Beneficial Ownership of Over Five Percent of Common Stock" and "Beneficial Ownership of Directors and Executive Officers" in the definitive Proxy Statement is incorporated by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENTS, SCHEDULES AND REPORTS ON FORM 8-K

A. INDEX

1. Consolidated Financial Statements

See Index on page 41.

2. Financial Statement Schedules

None.

3. Exhibits

The following instruments are included as exhibits to this report. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. If no parenthetical appears after an exhibit, copies of the instrument have been included herewith.

Exhibit Number	Description
3.1	Certificate of Incorporation of the Company (Registration Statement No. 33-32553).
3.2	Amended and Restated Bylaws of the Company amended September 6, 2001.
4.1	Form of Certificate of Common Stock of the Company (Registration Statement No. 33-32553).
4.2	Certificate of Designation for Series A Junior Participating Preferred Stock (Form 10-K for 1994).
4.3	Rights Agreement dated as of March 28, 1991, between the Company and The First National Bank of Boston, as Rights Agent, which includes as Exhibit A the form of Certificate of Designation of Series A Junior Participating Preferred Stock (Form 8-A, File No. 1-10477).
	(a) Amendment No. 1 to the Rights Agreement dated February 24, 1994 (Form 10-K for 1994).
	(b) Amendment No. 2 to the Rights Agreement dated December 8, 2000 (Form 8-K for December 21, 2000).
4.4	Certificate of Designation for 6% Convertible Redeemable Preferred Stock (Form 10-K for 1994).
4.5	Amended and Restated Credit Agreement dated as of May 30, 1995, among the Company, Morgan Guaranty Trust Company, as agent and the banks named therein.
	(a) Amendment No. 1 to Credit Agreement dated September 15, 1995 (Form 10-K for 1995).
	(b) Amendment No. 2 to Credit Agreement dated December 24, 1996 (Form 10-K for 1996).
4.6	Note Purchase Agreement dated May 11, 1990, among the Company and certain insurance companies parties thereto (Form 10-Q for the quarter ended June 30, 1990).
	(a) First Amendment dated June 28, 1991 (Form 10-K for 1994).
	(b) Second Amendment dated July 6, 1994 (Form 10-K for 1994).
4.7	Note Purchase Agreement dated November 14, 1997, among the Company and the purchasers named therein (Form 10-K for 1997).
4.8	Note Purchase Agreement dated as of July 26, 2001 among Cabot Oil & Gas Corporation and the Purchasers listed therein (Form 8-K for August 30,

2001).

10.1 Supplemental Executive Retirement Agreement between the Company and Charles P. Siess, Jr. (Form 10-K for 1995).

10.2 Form of Change in Control Agreement between the Company and Certain Officers.

10.3 Letter Agreement dated January 11, 1990, between Morgan Guaranty Trust Company of New York and the Company (Registration Statement No. 33-32553).

10.4 Form of Annual Target Cash Incentive Plan of the Company (Registration Statement No. 33-32553).

10.5 Form of Incentive Stock Option Plan of the Company (Registration Statement No. 33-32553).

(a) First Amendment to the Incentive Stock Option Plan (Post-Effective Amendment No. 1 to S-8 dated April 26, 1993).

Exhibit Number	Description
10.6	Form of Stock Subscription Agreement between the Company and certain executive officers and directors of the Company (Registration Statement No. 33-32553).
10.7	Transaction Agreement between Cabot Corporation and the Company dated February 1, 1991 (Registration Statement No. 33-37455).
10.8	Tax Sharing Agreement between Cabot Corporation and the Company dated February 1, 1991 (Registration Statement No. 33-37455).
10.9	Amendment Agreement (amending the Transaction Agreement and the Tax Sharing Agreement) dated March 25, 1991 (incorporated by reference from Cabot Corporation's Schedule 13E-4, Am. No. 6, File No. 5-30636).
10.10	Savings Investment Plan & Trust Agreement of the Company (Form 10-K for 1991).
	(a) First Amendment to the Savings Investment Plan dated May 21, 1993 (Form S-8 dated November 1, 1993).
	(b) Second Amendment to the Savings Investment Plan dated May 21, 1993 (Form S-8 dated November 1, 1993).
	(c) First through Fifth Amendments to the Trust Agreement (Form 10-K for 1995).
	(d) Third through Fifth Amendments to the Savings Investment Plan (Form 10-K for 1996).
10.11	Supplemental Executive Retirement Agreements of the Company (Form 10-K for 1991).
10.12	Settlement Agreement and Mutual Release (Tax Issues) between Cabot Corporation and the Company dated July 7, 1992 (Form 10-Q for the quarter ended June 30, 1992).
10.13	Agreement of Merger dated February 25, 1994, among Washington Energy Company, Washington Energy Resources Company, the Company and COG Acquisition Company (Form 10-K for 1993).
10.14	1990 Non-employee Director Stock Option Plan of the Company (Form S-8 dated June 23, 1990).
	(a) First Amendment to 1990 Non-employee Director Stock Option Plan (Post-Effective Amendment No. 2 to Form S-8 dated March 7, 1994).
	(b) Second Amendment to 1990 Non-employee Director Stock Option Plan (Form 10-K for 1995).
10.15	Second Amended and Restated 1994 Long-Term Incentive Plan of the Company.
10.16	Second Amended and Restated 1994 Non-Employee Director Stock Option Plan.
10.17	Employment Agreement between the Company and Ray R. Seegmiller dated September 25, 1995 (Form 10-K for 1995).
10.18	Form of Indemnity Agreement between the Company and Certain Officers (Form 10-K for 1997).

10.19	Deferred Compensation Plan of the Company as Amended September 1, 2001.
10.20	Trust Agreement dated September 2000 between Harris Trust and Savings Bank and the Company.
10.21	Lease Agreement between the Company and DNA COG, Ltd. dated April 24, 1998 (Form 10-K for 1998).
10.22	Credit Agreement dated as of December 17, 1998, between the Company and the banks named therein (Form 10-K for 1998).
10.23	Letter Agreement with Puget Sound Energy Company dated September 21, 1999 (Form 10-K for 1999).
10.24	Agreement and Plan of Merger, dated June 20, 2001, among Cabot Oil & Gas Corporation, COG Colorado Corporation, Cody Company and the shareholders of Cody Company (Form 8-K for June 28, 2001).
	(a) Amendment to Agreement and Plan of Merger dated as of July 10, 2001 to the Agreement and plan of Merger, dated June 20, 2001, among Cabot Oil & Gas Corporation, COG Colorado Corporation, Cody Company and the shareholders of Cody Company (Form 8-K for August 30, 2001).
	(b) Closing Agreement dated August 16, 2001 (Form 8-K for August 30, 2001).
10.25	Employment Agreement between the Company and Dan O. Dinges dated August 29, 2001.
21.1	Subsidiaries of Cabot Oil & Gas Corporation.
23.1	Consent of PricewaterhouseCoopers LLP.
23.2	Consent of Miller and Lents, Ltd.
28.1	Miller and Lents, Ltd. Review Letter dated February 8, 2002.

B. REPORTS ON FORM 8-K

Item 2: Acquisition or Disposition of Assets filing made on October 30, 2001 as an amendment to the August 30, 2001 Form 8-K. This amendment includes Item 7. Financial Statements and Exhibits.

Item 5: Other Events filing made on January 8, 2002 includes Item 7. Press Release dated December 14, 2001 and titled "Cabot Oil & Gas Announces Natural Gas Hedges."

Item 5: Other Events filing made on January 28, 2002 includes Item 7. Press Release dated January 22, 2002 and titled "Cabot Oil & Gas Provides 2001 Capital Program Update", and Item 7. Press Release dated January 24, 2002 and titled "Cabot Oil & Gas Announces Full Year and Fourth Quarter Results."

Item 5: Other Events filing made on February 20, 2002 includes Item 7. Press Release dated February 14, 2002 and titled "Cabot Oil & Gas Finalizes Year-End Reserves", and Item 7. Press Release dated February 19, 2002 and titled "Cabot Oil & Gas Chairman & CEO to Retire."

SIGNATURES

Pursuant to the requirements 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, in the City of Houston, State of Texas, on the 19/th/ of February 2002.

CABOT OIL & GAS CORPORATION

By: /s/ Ray R. Seegmiller

Ray R. Seegmiller
Chairman of the Board and
Chief Exective Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Ray R. Seegmiller Ray R. Seegmiller	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	February 19, 2002
/s/ Dan O. Dinges Dan O. Dinges	President and Chief Operating Officer	February 19, 2002
/s/ Scott C. Schroeder Scott C. Schroeder	Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 19, 2002
/s/ Henry C. Smyth Henry C. Smyth	Vice President and Controller (Principal Accounting Officer)	February 19, 2002
/s/ Robert F. Bailey Robert F. Bailey	Director	February 19, 2002
/s/ Henry O. Boswell Henry O. Boswell	Director	February 19, 2002
/s/ John G. L. Cabot John G. L. Cabot	Director	February 19, 2002
/s/ James G. Floyd James G. Floyd	Director	February 19, 2002
/s/ C. Wayne Nance C. Wayne Nance	Director	February 19, 2002

/s/ P. Dexter Peacock --------------------------- P. Dexter Peacock	Director	February 19, 2002
/s/ Charles P. Siess, Jr. --------------------------- Charles P. Siess, Jr.	Director	February 19, 2002
/s/ Arthur L. Smith --------------------------- Arthur L. Smith	Director	February 19, 2002
/s/ William P. Vititoe --------------------------- William P. Vititoe	Director	February 19, 2002