



Defining Value

2003 Annual Report



Cabot Oil & Gas Corporation



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Cabot Oil & Gas Corporation is engaged in the exploration, development, acquisition and exploitation of oil and gas properties. The Company is a leading domestic energy producer with substantial interests in the Texas and Louisiana Gulf Coast, the Western region with operations in the Rocky Mountains and Mid-Continent, the Eastern region and an expansion effort in Canada.



Financial Highlights

	Year Ended December 31,		
	2003	2002	2001
Financial Data <i>(In millions, except share amounts)</i>			
Operating Revenues	\$ 509.4	\$ 353.8	\$ 447.0
Net Income	\$ 21.1	\$ 16.1	\$ 47.1
Per Share	\$ 0.66	\$ 0.51	\$ 1.56
Discretionary Cash Flow ⁽¹⁾	\$ 266.4	\$ 178.8	\$ 230.5
Per Share	\$ 8.31	\$ 5.63	\$ 7.61
Capital and Exploration Expenditures ⁽²⁾	\$ 188.2	\$ 126.3	\$ 453.4
Common Dividends per Share	\$ 0.16	\$ 0.16	\$ 0.16
Average Common Shares Outstanding <i>(In thousands)</i>	32,050	31,737	30,276
Capitalization <i>(In millions)</i>			
Long-term Debt	\$ 270.0	\$ 365.0	\$ 393.0
Shareholders' Equity <i>(Successful Efforts Method)</i>	\$ 365.2	\$ 350.7	\$ 346.6
Annual Production Volume			
Bcfe	89.0	91.1	81.1
% Growth	(2%)	12%	21%
% Gas	81%	81%	85%
Proved Reserves ⁽³⁾			
Natural Gas <i>(Bcf)</i>	1,069.5	1,061.0	1,036.0
Oil, Condensate and Natural Gas Liquids <i>(Mmbbl)</i>	12.1	18.4	19.7
Total Proved <i>(Bcfe)</i>	1,142.1	1,171.3	1,154.1
% Gas	94%	91%	90%
% Developed	76%	77%	78%
Reserve Life <i>(Years)</i>	12.8	12.9	14.2
Reserve Additions			
Drilling Additions <i>(Bcfe)</i>	115.8	70.1	113.5
Drilling Additions, Revisions and Purchases <i>(Bcfe)</i>	113.1	123.5	217.5
Reserve Replacement %	127%	136%	268%
Reserve Replacement Cost – Additions <i>(\$ per Mcfe)</i>	\$ 1.41	\$ 1.46	\$ 1.70
Reserve Replacement Cost – Additions, Revisions and Purchases <i>(\$ per Mcfe)</i>	\$ 1.46	\$ 0.90	\$ 2.01
Wells Drilled			
Total Gross	173	108	208
Total Net	132.0	72.2	154.0
Gross Success Rate %	89%	93%	87%
Produced Average Natural Gas Sales Price <i>(\$ per Mcf)</i>			
Gulf Coast	\$ 4.78	\$ 3.34	\$ 4.44
West	\$ 3.67	\$ 2.39	\$ 3.88
East	\$ 5.15	\$ 3.38	\$ 4.96
Total Company	\$ 4.51	\$ 3.02	\$ 4.36
Crude and Condensate Price <i>(\$ per Bbl)</i>			
	\$ 29.55	\$ 23.79	\$ 24.91

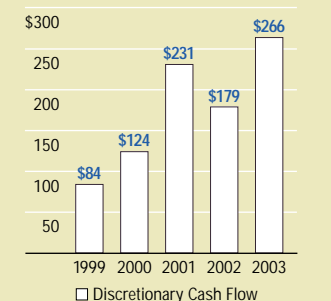
⁽¹⁾ Net income plus non-cash items from operations and exploration expenses.

⁽²⁾ 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.

⁽³⁾ Changes in reserves from year to year reflect drilling additions and revisions as well as reserves purchased and sold. See page 80 of this report for details.



Discretionary Cash Flow (In millions)



Cabot's drilling program expanded significantly in 2003. The Company's drilling activity (as measured by wells) increased by nearly 60 percent in 2003 over 2002. During the course of that time we experienced a 97 percent rate of success for development wells and 46 percent success rate for exploration wells, for a combined overall success rate of 89 percent.

Cabot reduced debt by \$95 million. Since year-end 2002, debt has been reduced from \$365 million to \$270 million. The Company now has reduced the outstanding balance on its Credit Facility to zero, providing Cabot \$250 million of immediate financing capacity.

Letter to Shareholders

Leading the way for 2003 were unmatched full-year commodity prices that afforded Cabot a record level of cash flow allowing the Company to ramp up its capital program, while still repaying \$95 million in debt.

If you recall in last year's letter, two of our overriding goals for 2003 were: (1) to balance our capital program through increased investment in development drilling along with expanding the number of exploration opportunities; and (2) to continue to improve our balance sheet primarily through the reduction in debt. Both of these goals were accomplished. In addition, during 2003 we were able to achieve several other goals.

Replace Production with the Drillbit. In 2003 the Company replaced 127 percent of its production at a value added price of \$1.46 per Mcfe. Due to selling low-margin, low-growth properties in Pennsylvania and central Texas, total proved reserves were 1,142 Bcfe at year end; slightly lower than the 1,171 Bcfe reported at December 31, 2002.

Maintain Profitability. In spite of a significant non-cash write down in the first quarter of 2003, Cabot was able to report higher net income in 2003 versus 2002. For the year, net income was \$21.1 million compared to \$16.1 million for 2002. At the same time, discretionary cash flow grew 49 percent year-over-year to a record \$266.4 million, or \$8.31 per share.

Establish Two New Play Concepts. To complement our infrastructure expansion in the East, we have developed a "commodity play" in West Virginia that provides Cabot a high number of relatively low-risk drilling locations that will be drilled over the next several years. In the West region with the Wind Dancer discovery in the Wyoming, Green River Basin, the Company has a "basin-centered gas play" that affords Cabot a number of development drilling locations to fully exploit the field over the next two to three years.

Improve Asset Portfolio. During the year we focused on new ventures for the longer term. We moved offshore as a complement to our onshore Gulf Coast position and were successful in our initial effort to secure a leasehold position, winning 15 of 20 bids at the federal offshore lease sale. Concurrent with this effort, we opened a Canadian office focused on an organic drilling strategy.

Expand Takeaway Capacity (in the East). Through \$8 million of investment, we were able to expand our pipeline capacity in certain areas by 46 Mmcfe per day. This was accomplished with new compressors in six locations, the laying of additional pipelines and the purchase of approximately 52 miles of 10-inch pipeline that runs from our Danville operations to markets in Charleston, West Virginia.

All things considered, 2003 was a very successful year for Cabot Oil & Gas with value creation for its shareholders and enhanced opportunities for 2004.



Continuing Momentum in 2004

As we look forward to 2004, our \$200 million capital program focuses on an expanded effort in the East and Canada, a targeted Western program and a diversified exploration program in the Gulf Coast – balanced between onshore and offshore.

- Our program provides for drilling 276 wells, including 246 development and 30 exploration wells, up from 145 and 28 wells, respectively, in 2003. Drilling investment totals \$134 million, of which, 40 percent is allocated for the Gulf Coast, 30 percent for the East, 24 percent for the West and 6 percent for Canada.
- We will focus on our commodity play in the East where we expect to drill 179 wells on our position that covers approximately one million net acres. The combination of these wells and the completed infrastructure enhancements provide the catalyst for the second consecutive year of growth in regional production and reserves.
- Our basin-centered gas play in the Rocky Mountains will focus on two areas. First, we will continue

developing our Wind Dancer field, drilling 10 wells there in 2004. Second, we will continue our exploration program with six wells in an effort to discover another basin-centered gas play in the region.

- In the Gulf Coast, a balance of onshore and offshore program investment dollars will be maintained. In 2004, we have planned seven onshore and five offshore exploration projects.
- Our focus on organic expansion in Canada will continue through our joint ventures. We have budgeted eight exploration wells for 2004. Our Canadian staff will continue to search for additional exploration opportunities that provide significant resource exposure.
- The commodity pricing environment continues to be volatile and somewhat irrational when one looks at fundamentals (storage, supply, demand, etc.). Therefore, we continued our layering approach for hedging and at the date of this report, our hedge position covers nearly 75 percent of anticipated 2004 natural gas production. These hedges were driven off NYMEX prices, which when

averaged, were above \$5.00 per Mcf. Nearly 70 percent of oil production is hedged through range swaps at \$29.20 per barrel, unless the oil price average falls below \$22.00 during the monthly measurement period (versus 45 percent at \$27.35 per barrel in 2003).

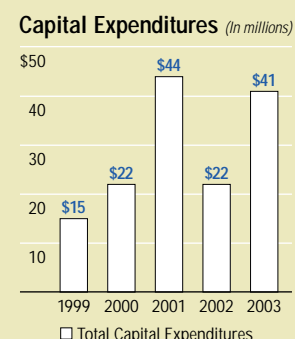
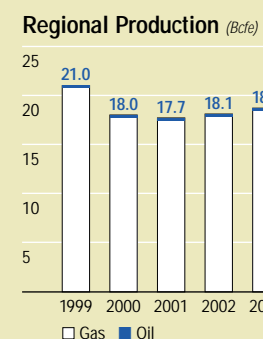
- We will continue to assess the acquisition market. However, with this price environment buyers' and sellers' expectations have continued to widen. In 2003 we looked at several opportunities across all regions and were successful on a pipeline purchase in the East.

Cabot has the unique position of being a niche player in several basins with a diversified exploration program and significant financial flexibility. We will continue to replenish our drilling inventory, exercise sound financial judgment and assess potential acquisitions to deliver value creation for the benefit of our shareholders.

Sincerely,

Dan O. Dinges

Chairman, President and Chief Executive Officer



2003 Production	
Bcfe	18.7
% of Total	21%
Daily Volumes (<i>Mmcfe per day</i>)	51.4
Gross Wells	
	2,418
% Company Operated	96.5%
Total Net Acreage	
	898,957
Net Developed Acreage	723,484
Net Undeveloped Acreage	175,473

2003 Proved Reserves	
Proved Reserves (<i>Bcfe</i>)	491.8
% of Total	43%
% Developed	73%
Reserve Life (<i>Years</i>)	26.2

2003 Capital Program	
Capital Expenditures	\$ 40.6
% of Capital Expenditures	22%
Wells Drilled	
Gross	98
Net	91.4

2004 Drilling Program	
% of Drilling Budget	30%
Planned Wells	179

Rediscovering Our Roots in the East

Cabot has been active in the natural gas business in the eastern United States for more than 110 years. The Eastern region continues to provide Cabot with a reliable commodity play that provides growth potential in both reserves and production. Over the years, Cabot's level of capital commitment has varied depending on commodity prices, however this basin has always been an important part of the Company's overall reserve portfolio. In 2003 Cabot drilled 98 gross wells (91 net) in the region, up from 44 gross wells (39 net) in 2002, with a drilling success rate of 97 percent. The majority of drilling occurred in West Virginia, specifically the Pineville and Danville districts, including several wells that far exceeded typical Eastern well initial flow rates.

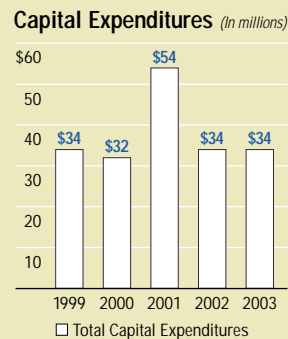
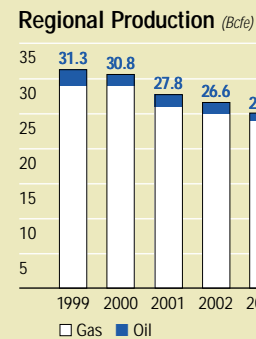
Production grew 3.3 percent year-over-year on the strength of these successes, even after the sale of non-strategic properties. The result is a reserve base of 491.8 Bcf that accounts for 43 percent of the Company's portfolio. The sale included the Company's remaining Pennsylvania properties and two water treatment plants that handled water production associated with gas production from that area. The transactions garnered \$19.4 million.

Also in 2003, Cabot invested strategically in infrastructure improvements totaling \$8 million for compressor upgrades and laying additional pipelines. Separately, the Company purchased approximately 52 miles of additional pipeline between its Danville district and Charleston. (The map above illustrates the pipeline acquisition and the locations of the compressor upgrades.) These investments were throughout West Virginia, covering several key production outlets. Now with these upgrades completed, takeaway capacity in certain areas is 46 Mmcf per day greater than before.

2004 and Beyond

Because of the Company's strong acreage position in the East, which is approaching one million net acres, and the infrastructure investments; the Company has "rediscovered" this region as a growth area. The capital program has been expanded from 98 wells in 2003 to 179 in 2004 and is dominated by development drilling that is repeatable for years to come. Conservatively estimating, based on the existing knowledge of the basin and technology, Cabot has a four-year inventory of identified locations with a considerable amount of additional undeveloped acreage to exploit.





2003 Production	
Bcfe	24.9
% of Total	28%
Daily Volumes (Mmcfe per day)	68.3
Gross Wells	
% Company Operated	67.0%
Total Net Acreage	
Net Developed Acreage	269,442
Net Undeveloped Acreage	402,824

2003 Proved Reserves	
Proved Reserves (Bcfe)	425.7
% of Total	37%
% Developed	82%
Reserve Life (Years)	17.1

2003 Capital Program	
Capital Expenditures	\$ 33.5
% of Capital Expenditures	19%
Wells Drilled	
Gross	34
Net	20.5

2004 Drilling Program		U.S.	Canada
% of Drilling Budget	24%	6%	
Planned Wells	56	8	

Exploring the West

The Western region consists of Mid-Continent assets and the Company’s investment in the Paradox, Green River and Wind River Basins in the Rocky Mountains. This region holds 37 percent of the total proved reserves of the Company. Cabot’s objectives in the West have been to use excess cash flow from the predictable legacy assets in the Mid-Continent for exploration investment in the Rocky Mountains and Gulf Coast regions.

Cabot has been a participant in the Mid-Continent since the 1930s, most recently focusing its efforts in this basin on solid rates of return and forgoing production growth. After an extremely small drilling program in 2002, the Company expanded its effort in the area in 2003 with a development effort that had 13 successes in 15 attempts. Noteworthy success was found on new leases that provided for the majority of our drilling locations. Cabot plans to continue this method of exploiting the Mid-Continent.

In the Rocky Mountains, Cabot continued its focus in the Paradox Basin where it drilled 10 successful wells in 13 attempts and increased production from zero to 28 Mmcfe per day gross since starting there in 2001. Due to this continued success Cabot has been required to continually invest in infrastructure, most recently in compression and treatment (processing) facilities, where plant capacity has been increased to 42 Mmcf per day gross. This level of production is anticipated with success from the 2004 program.

Cabot realized its first major exploration success in the Rocky Mountains with the Wind Dancer #10-28 well on the Nickey prospect in the Wyoming Green River Basin. Originally spud as an Almond test, the well was drilled to a total depth of 11,700 feet and encountered pay in the Lance, Lewis and Almond formations with significant offset potential. As of the date of this writing, three productive offset wells have been drilled in the field, reinforcing early thoughts that this discovery truly set up the anticipated basin-centered gas play.

2004 Drilling Program

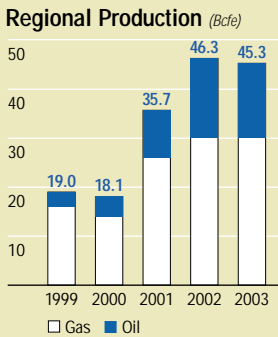
The program in the West will focus on further development in the Green River and Paradox Basins, along with continuation of the exploration effort. The Company has conservatively identified approximately 30 development locations in the Nickey prospect. If the field develops as planned, 20 additional offset locations are not out of the question. This inventory would provide development drilling locations for a three- to five-year period.

In terms of exploration for 2004, Cabot has identified six wells that expose the Company to an estimated 120 to 450 Bcfe net unrisks reserve potential. Two of the wells are located in the Paradox Basin and one in each of the Bighorn, Green River, Wind River and Anadarko basins. Due primarily to permitting requirements, the wells are scheduled for drilling in the second and third quarters.

Moving North to Canada

As an extension of Cabot’s operations, the Company formally initiated entrance into Canada in 2003 with a focus on organic expansion looking for significant reserve potential. Through two joint ventures, the Company continues to evaluate 25,000 kilometers of modern 2-D seismic data and has laid the groundwork for drilling eight wells in 2004. These wells provide an estimated 40 to 70 Bcfe of net risks exposure.





2003 Production	
Bcfe	45.3
% of Total	51%
Daily Volumes (<i>Mmcfe per day</i>)	124.1
Gross Wells	747
% Company Operated	75.2%

Total Net Acreage		191,645
Net Developed Acreage	89,844	
Net Undeveloped Acreage	101,801	

2003 Proved Reserves	
Proved Reserves (Bcfe)	224.6
% of Total	20%
% Developed	72%
Reserve Life (Years)	5.0

2003 Capital Program	
Capital Expenditures	\$111.6
% of Capital Expenditures	59%
Wells Drilled	
Gross	41
Net	20.1

2004 Drilling Program	
% of Drilling Budget	40%
Planned Wells	33

Strengthening Our Gulf Presence

Cabot's Gulf Coast region, which encompasses its onshore and offshore holdings stretching from south Texas to eastern Louisiana, had a positive year in terms of positioning the region for the future. These successes, however, were not able to overcome the production decline from our high-rate discoveries of late 1999 and early 2000 on the Continental Land & Fur (CL&F) leasehold. (See the Gulf Coast Region Net Daily Production chart for more details.)

The region's drilling success exceeded budgeted expectations. This was driven by continued success in Red Fish Bay, exploitation of certain fields purchased in the 2001 Cody acquisition and continued exploitation of the Chacahoula field. Combined, this year's drilling program added 38 Mmcfe per day to production by the end of 2003.

The 2002 annual report discussed two new initiatives, including a move off-shore to complement Cabot's existing onshore Gulf Coast portfolio and a large lease option in north Louisiana. Significant progress has been made in the off-shore arena. First, the Company was successful in securing leases on 15 federal offshore blocks – thus creating an immediate inventory of prospects. Second, as a result of last year's retention of a prospect generation team and various opportunities from industry partners, the Company participated in the drilling of seven exploration wells, of which 57 percent were successful. With this success and the associated lead time for initial production, Cabot met its goal of establishing production overhang (volumes that are simply waiting for facilities) with an estimated 24 Mmcfe per day net expected by November 2004.

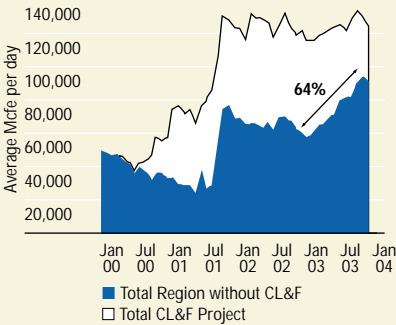
With regard to the north Louisiana lease option, Cabot spent most of 2003 identifying prospects, a process that will continue into 2004. Cabot has identified several significant prospects based on early work, one of which will be drilled in 2004.

2004 and Beyond

The Gulf Coast drilling program for 2004 will once again focus on exploration, with seven exploration wells scheduled onshore and five scheduled offshore, in addition to a number of development wells. This reflects Cabot's ongoing focus of balancing its exploration program between onshore and offshore within the region. In total, this program provides exposure to an estimated 125 to 200 Bcfe of net unrisked reserve potential.



Gulf Coast Region Net Daily Production



The prolific discoveries at Etouffee, Bon Ton and Augen, drilled in 1999 and 2000, have begun a steep decline. This was expected to start in late 2003, but water encroachment occurred earlier in 2003 than anticipated. Due to this decline, the Company saw production reduced by 4.7 Bcfe for the year.

While the decline was inevitable, the result has a positive implication. At the start of the year the Gulf Coast region relied on the CL&F lease for 50 percent of its daily production. By year-end that number was down to 25 percent, with the region's daily production level still matching the level at the beginning of the year. This reflected the success of the region's program outside of CL&F lease. The region's production is currently better balanced than any time in its history.

Board of Directors

Committees

Audit Committee

John G. L. Cabot – *Chairman*
Robert F. Bailey
Robert Kelley
P. Dexter Peacock

Compensation Committee

William P. Vititoe – *Chairman*
John G. L. Cabot
James G. Floyd
Robert Kelley

Executive Committee

P. Dexter Peacock – *Chairman*
John G. L. Cabot
Dan O. Dinges
C. Wayne Nance

Corporate Governance and Nominations Committee

James G. Floyd – *Chairman*
C. Wayne Nance
P. Dexter Peacock
William P. Vititoe

Safety & Environmental Affairs Committee

Robert F. Bailey – *Chairman*
James G. Floyd
William P. Vititoe

Directors

Dan O. Dinges

Chairman, President and
Chief Executive Officer

Robert F. Bailey

B&J Exodus, Ltd.
(private investment partnership)
Former President and
Chief Executive Officer,
TransRepublic Resources, Inc.

John G. L. Cabot

Former Vice Chairman of the Board
and Chief Financial Officer,
Cabot Corporation

James G. Floyd

Former President, Chief Executive
Officer and Director, Houston
Exploration Company

Robert Kelley

Kellco Investments –
(private investment company)
Former Chairman of the Board,
President and Chief Executive
Officer, Noble Affiliates, Inc.

C. Wayne Nance

Senior Vice President,
The Mitchell Group (equity
investment advising)
Former President,
Tenneco Oil Company

P. Dexter Peacock

Of Counsel, Andrews & Kurth L.L.P.
Former Managing Partner,
Andrews & Kurth L.L.P.

William P. Vititoe

Former Chairman of the Board,
Chief Executive Officer and
President, Washington Energy
Company

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, 2003**
Commission file number **1-10447**

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

04-3072771
(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
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 ☐ .

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).

Yes ☒ X

No ☐

The aggregate market value of 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 June 30, 2003), the last business day of registrant's most recently completed second fiscal quarter was approximately \$889,100,000.

As of January 30, 2004, there were 32,390,158 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held April 29, 2004 are incorporated by reference into 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," "will" 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 of 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 North America. The five principal areas of operation are the Texas and Louisiana Gulf Coast, Rocky Mountains, Anadarko Basin, Appalachian Basin and the gas basin of Western Canada. In 2003 we initiated limited operations in Canada. Operationally, we have regional offices located in the Gulf Coast region, the Western region, which is comprised of the Rocky Mountains and Mid-Continent areas, the Eastern region and Canada.

In 2003, energy commodity prices remained strong throughout the year. We leveraged the strong price environment to pay down debt and put Cabot in a financial position to take advantage of attractive acquisition opportunities. At December 31, 2003 our debt to total capital ratio was 43%, down from 51% at the end of 2002. Our production level in 2003 was down slightly from 2002, the year gas and oil production reached the highest annual level in our history. We produced 89.0 Bcfe, or 243.8 Mmcfe per day this year compared to 91.1 Bcfe, or 249.7 Mmcfe per day in 2002. To continue to take advantage of the unusually strong price environment, we layered in oil and gas hedge instruments throughout 2003 to cover production in 2003, 2004 and to a lesser extent 2005. At December 31, 2003, 76% and 72% of our natural gas and crude oil anticipated production, respectively, is hedged for 2004. For 2005 we have hedged 16% of our anticipated natural gas. We do not have any open positions on anticipated 2005 crude oil production. Our decision to hedge this production fits with our risk management strategy and will allow the Company to lock in the benefit of high commodity prices. Our 2003 realized natural gas price was \$4.51 per Mcf, compared to a 2002 price of \$3.02. Our realized crude oil price was \$29.55 per Bbl, compared to a 2002 price of \$23.79. Our average hedged prices on natural gas and crude oil for 2004 anticipated production are expected to be higher than comparable prices realized from hedging in 2003.

Net income of \$21.1 million or \$0.66 per share exceeded last year by \$5.0 million or \$0.15 per share. Net Operating Revenues increased by \$155.6 million or 44% due to strong commodity prices. The year over year increase in net income was achieved despite the non-cash pre-tax impairment charges of \$93.8 million and the \$6.8 million impact of a cumulative effect of accounting change. The pre-tax non-cash impairment charges consist of \$87.9 million related to the liquidation of a limited partnership interest in the Kurten field and \$5.9 million related to a field in the East. The cumulative effect of accounting change is related to a \$6.8 million charge from the adoption of SFAS 143. These charges were partially offset by a pre-tax gain of \$12.2 million recognized primarily on the sale of non-strategic oil and gas properties.

For the year ended December 31, 2003, we drilled 173 gross wells with a success rate of 89% compared to 108 gross wells with a success rate of 93% for the comparable period of the prior year. Our 2003 capital and exploration spending was \$188.2 million compared to \$126.3 million in 2002. We concentrated our 2003 capital spending program on projects balancing acceptable risk with the strongest economics. In the past, we have used a portion of the cash flow from our long-lived Eastern and Mid-Continent natural gas reserves to fund our exploration and development efforts in the Gulf Coast, Canada and Rocky Mountain areas. In 2003, certain non-strategic assets were sold in the East region. Despite this divestiture, production increased in this region as a result of the drilling program and infrastructure enhancements. Our growth plans for the East region have been redefined for 2004. Accordingly, the East will join the Gulf Coast and Rocky Mountain areas as a focal point of value enhancement efforts through accretive reserve and production growth in 2004. In 2004, we plan to spend \$207.4 million and drill 276 gross wells.

Our proved reserves totaled approximately 1,142 Bcfe at December 31, 2003, of which 94% was natural gas. This reserve level was down slightly from 1,171 Bcfe at December 31, 2002 due to 53.4 Bcfe of proved reserve asset sales.

The following table presents certain information as of December 31, 2003.

	Gulf Coast	Rocky Mountains	West Mid-Continent	Total West	East	Total
Proved Reserves at Year End (<i>Bcfe</i>)						
Developed _____	161.1	183.4	166.9	350.3	357.3	868.7
Undeveloped _____	63.5	49.4	26.0	75.4	134.5	273.4
Total	224.6	232.8	192.9	425.7	491.8	1,142.1
Average Daily Production (<i>Mmcfe per day</i>) _____	124.1	40.3	28.0	68.3	51.4	243.8
Reserve Life Index (<i>In years</i>) ⁽¹⁾ _____	5.0	15.8	18.9	17.1	26.2	12.8
Gross Wells _____	747	505	618	1,123	2,418	4,288
Net Wells ⁽²⁾ _____	504.1	226.1	430.9	657.0	2,237.4	3,398.5
Percent Wells Operated (<i>Gross</i>) _____	75.2%	51.9%	79.3%	67.0%	96.5%	85.1%

⁽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 the Gulf Coast region are primarily concentrated in south Louisiana, south Texas and the Gulf of Mexico. A regional office in Houston manages operations. Principal producing intervals are in the Miocene and Frio age formations in Louisiana and the Frio, Vicksburg, and Wilcox formations in Texas at depths ranging from 3,000 to 20,500 feet. Capital and exploration expenditures were \$111.6 million for 2003, or 59% of our total 2003 capital and exploration expenditures, and \$69.0 million for 2002. For 2004, we have budgeted \$87.9 million of our total budget for capital and exploration expenditures in the region. Our 2004 Gulf Coast drilling program will emphasize impact exploration opportunities both on and offshore augmented by development activity in our focus areas of south Texas and coastal Louisiana, including properties acquired in the Cody acquisition.

In 2003, we drilled 41 wells (20.1 net) in the Gulf Coast region, of which 23 wells (11.6 net) were development wells. In 2004 we plan to drill 33 wells. We had 747 wells (504.1 net) in the Gulf Coast region as of December 31, 2003, of which 562 wells are operated by us. Average daily production in 2003 was 124.1 Mmcfe, compared to 127.0 Mmcfe in 2002. The decline is the result of lower production from our properties in south Louisiana offset partially by increased production from the coastal Texas area. At December 31, 2003, we had 224.6 Bcfe of proved reserves (76% natural gas) in the Gulf Coast region, which represented 20% of our total proved reserves.

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 the natural gas production from our operated wells in the Gulf Coast region. The marketing subsidiary sells the natural gas to intrastate pipelines, natural gas processors and marketing companies.

Currently, approximately 60% 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 40% of our sales volumes are sold at index-based prices under short-term agreements. 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 currently also produce and market approximately 7,100 barrels of crude oil/condensate per day 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, 2003, we had 425.7 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 of Wyoming and Paradox Basin in Colorado. At December 31, 2003 we had 232.8 Bcfe of proved reserves. Capital and exploration expenditures in the Rocky Mountains were \$22.3 million for 2003, or 12% of our total capital and exploration expenditures, and \$25.9 million for 2002. Current year spending includes \$10.9 million for drilling activity and \$9.4 million of dry hole expense and geo-physical and geological procedures. For 2004, we have budgeted \$29.9 million for capital and exploration expenditures in the area.

We had 505 wells (226.1 net) in the Rocky Mountains area as of December 31, 2003, of which 262 wells are operated by us. Principal producing intervals in the Rocky Mountains area are in the Almond, Frontier, Dakota, and Honaker Trail formations at depths ranging from 9,000 to 13,500 feet. Average net daily production in the Rocky Mountains during 2003 was 40.3 Mmcfe.

In 2003, we drilled 19 wells (8.9 net) in the Rocky Mountains, of which 15 wells (6.7 net) were development and extension wells. In 2004, we plan to drill 26 wells.

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 \$11.2 million for 2003, or 6% of our total 2003 capital and exploration expenditures, and \$8.2 million for 2002. For 2004, we have budgeted \$17.5 million for capital and exploration expenditures in the area.

As of December 31, 2003, we had 618 wells (430.9 net) in the Mid-Continent area, of which 490 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 2003 was 28.0 Mmcfe. At December 31, 2003, we had 192.9 Bcfe of proved reserves (97% natural gas) in the Mid-Continent area, 17% of our total proved reserves.

In 2003, we drilled 15 wells (11.6 net) in the Mid-Continent, all of which were development wells. In 2004, we plan to drill 30 wells.

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

Currently, approximately 75% 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 23% 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. The Western region properties are connected to the majority of the midwestern and northwestern interstate and intrastate pipelines, affording us access to multiple markets.

We currently also produce and market approximately 500 barrels of crude oil/condensate per day in the Western region at market responsive prices.

Eastern Region

Our Eastern activities are concentrated in West Virginia, 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. Capital and exploration expenditures were \$40.6 million for 2003, or 22% of our total 2003 capital spending, and \$22.1 million for 2002. For 2004, we have budgeted \$57.9 million for capital and exploration expenditures in the region.

At December 31, 2003, we had 2,418 wells (2,237.4 net), of which 2,334 wells are operated by us. There are multiple producing intervals that include the Big Lime, Weir, Berea, Devonian Shale and Oriskany formations at depths primarily ranging from 1,500 to 9,000 feet. Average net daily production in 2003 was 51.4 Mmcfe. While natural gas production volumes from Eastern reservoirs are relatively low on a per-well basis compared to other areas of the United States, the productive life of Eastern reserves is relatively long. At December 31, 2003, we had 491.8 Bcfe of proved reserves (substantially all natural gas) in the Eastern region, constituting 43% of our total proved reserves. This region is managed from our office in Charleston, West Virginia.

In 2003, we drilled 98 wells (91.4 net) in the Eastern region, of which 92 wells (86.2 net) were development wells. In 2004, we plan to drill 179 wells.

Ancillary to our exploration, development and production operations, we operate a number of gas gathering and transmission pipeline systems with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2003. 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 3 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 Eastern region. The pipeline systems and storage fields are fully integrated with our operations.

In 2003 we purchased 52 miles of pipeline which enables us to deliver gas in a more efficient manner from an existing producing field. Additionally, this acquisition will allow us to deliver gas to certain industrial facilities in West Virginia.

In addition, during most of 2003 we owned and operated two brine treatment plants that processed and treated waste fluid generated during the drilling, completion and production of oil and gas wells. The first plant, near Franklin, Pennsylvania, began operating in 1985 and provided 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. Effective November 1, 2003, we sold this wholly owned subsidiary, Franklin Brine Corporation for \$3.4 million in cash, and no longer own or operate any brine treatment facilities.

The principal markets for our Eastern region natural gas are in the northeastern United States. Cabot Oil & Gas Marketing purchases our natural gas production in the Eastern region as well as production from local third-party producers and other suppliers to aggregate larger volumes of natural gas for resale. The 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 Eastern 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 2% of Eastern production is sold on fixed price contracts that typically renew annually.

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 in all of our regions. While there are many different types of derivatives available, in 2003 we primarily employed natural gas and oil price swap and 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 or crude oil for the period is greater or less than the fixed price established for that period when the swap is put in place. The 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.

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, 2003.

	Natural Gas (Mmcf)			Liquids⁽¹⁾ (Mbbbl)			Total⁽²⁾ (Mmcfe)		
	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	Total
Gulf Coast_____	121,476	50,163	171,639	6,603	2,216	8,819	161,095	63,459	224,554
Rocky Mountains____	173,893	46,739	220,632	1,592	443	2,035	183,447	49,399	232,846
Mid-Continent_____	161,965	25,795	187,760	820	39	859	166,884	26,031	192,915
East_____	354,946	134,507	489,453	390	—	390	357,286	134,507	491,793
Total	812,280	257,204	1,069,484	9,405	2,698	12,103	868,712	273,396	1,142,108

⁽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 2003.

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

Historical Reserves

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

	Natural Gas (Mmcf)	Oil & Liquids (Mbbbl)	Total (Mmcf) ⁽¹⁾
December 31, 2000	959,222	9,914	1,018,703
Revision of Prior Estimates	(44,266)	254	(42,737)
Extensions, Discoveries and Other Additions	99,911	2,257	113,456
Production	(69,162)	(1,996)	(81,139)
Purchases of Reserves in Place	91,290	9,255	146,819
Sales of Reserves in Place	(991)	—	(993)
December 31, 2001	1,036,004	19,684	1,154,109
Revision of Prior Estimates	14,405	1,871	25,631
Extensions, Discoveries and Other Additions	64,945	851	70,053
Production	(73,670)	(2,909)	(91,126)
Purchases of Reserves in Place	26,262	261	27,828
Sales of Reserves in Place	(6,987)	(1,365)	(15,179)
December 31, 2002	1,060,959	18,393	1,171,316
Revision of Prior Estimates	(6,122)	307	(4,278)
Extensions, Discoveries and Other Additions	105,497	1,723	115,835
Production	(71,906)	(2,846)	(88,976)
Purchases of Reserves in Place	1,590	—	1,591
Sales of Reserves in Place	(20,534)	(5,474)	(53,380)
December 31, 2003	1,069,484	12,103	1,142,108

Proved Developed Reserve

December 31, 2000	754,962	8,438	805,590
December 31, 2001	804,646	15,328	896,612
December 31, 2002	819,412	13,267	899,016
December 31, 2003	812,280	9,405	868,712

⁽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.

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,		
	2003	2002	2001
Net Wellhead Sales Volume			
Natural Gas (<i>Bcf</i>)			
Gulf Coast	30.0	30.4	25.6
West	23.8	25.3	26.2
East	18.6	18.0	17.4
Crude/Condensate/Ngl (<i>Mbbl</i>)			
Gulf Coast	2,625	2,655	1,694
West	193	221	267
East	27	33	35
Produced Natural Gas Sales Price (\$/Mcf) ⁽¹⁾			
Gulf Coast	\$ 4.78	\$ 3.34	\$ 4.44
West	3.67	2.39	3.88
East	5.15	3.38	4.96
Weighted Average	4.51	3.02	4.36
Crude/Condensate Sales Price (\$/Bbl) ⁽¹⁾	\$ 29.55	\$ 23.79	\$ 24.91
Production Costs (\$/Mcf) ⁽²⁾	\$ 0.87	\$ 0.70	\$ 0.72

⁽¹⁾ Represents the average sales price (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.

Leasehold Acreage

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
State						
Arkansas _____	1,981	425	0	0	1,981	425
Colorado _____	16,389	14,156	204,755	111,338	221,144	125,494
Kansas _____	29,067	27,745	0	0	29,067	27,745
Kentucky _____	2,266	901	0	0	2,266	901
Louisiana _____	50,963	41,853	16,604	14,277	67,567	56,130
Michigan _____	544	157	0	0	544	157
Montana _____	397	210	35,444	27,759	35,841	27,969
New York _____	2,956	1,117	8,531	8,222	11,487	9,339
New Mexico _____	160	36	0	0	160	36
North Dakota _____	0	0	870	96	870	96
Ohio _____	6,273	2,409	1,613	428	7,886	2,837
Oklahoma _____	164,138	114,338	8,638	6,307	172,776	120,645
Pennsylvania _____	111,953	63,752	3,797	2,561	115,750	66,313
Texas _____	105,562	73,099	54,405	31,605	159,967	104,704
Utah _____	1,740	529	173,326	91,962	175,066	92,491
Virginia _____	22,195	20,072	6,286	4,660	28,481	24,732
West Virginia _____	571,405	537,286	132,228	108,405	703,633	645,691
Wyoming _____	139,340	71,173	287,233	164,087	426,573	235,260
Federal Offshore _____	4,995	1,162	90,420	56,047	90,420	56,047
Total	1,232,324	970,420	1,024,150	627,754	2,256,474	1,598,174

Mineral Fee Acreage

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
State						
Colorado _____	0	0	2,899	567	2,899	567
Kansas _____	160	128	0	0	160	128
Louisiana _____	628	276	0	0	628	276
Montana _____	0	0	589	75	589	75
New York _____	0	0	4,281	1,070	4,281	1,070
Oklahoma _____	16,580	13,979	730	179	17,310	14,158
Pennsylvania _____	880	880	1,573	502	2,453	1,382
Texas _____	327	177	652	326	979	503
Virginia _____	17,817	17,817	100	34	17,917	17,851
West Virginia _____	97,455	79,093	50,740	49,591	148,195	128,684
Total	133,847	112,350	61,564	52,344	195,411	164,694
Aggregate Total	1,366,171	1,082,770	1,085,714	680,098	2,451,885	1,762,868

Total Net Acreage by Region of Operation

	Developed	Undeveloped	Total
Gulf Coast _____	89,844	101,801	191,645
West _____	269,442	402,824	672,266
East _____	723,484	175,473	898,957
Total	1,082,770	680,098	1,762,868

Well Summary

The following table presents our ownership at December 31, 2003, 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 Eastern region (consisting of various fields located in West Virginia, Virginia and Ohio). This summary includes natural gas and oil wells in which we have a working interest.

	Natural Gas		Oil		Total ⁽¹⁾	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast _____	584	360.9	163	143.2	747	504.1
West _____	1,068	625.5	55	31.5	1,123	657.0
East _____	2,393	2,225.3	25	12.1	2,418	2,237.4
Total	4,045	3,211.7	243	186.8	4,288	3,398.5

⁽¹⁾ Total does not include service wells of 60 (48.6 net).

Drilling Activity

We drilled wells, participated in the drilling of wells, or acquired wells as indicated in the region table below.

Year Ended December 31, 2003								
	Gulf Coast		West		East		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells								
Successful _____	23	11.6	26	14.9	91	85.2	140	111.7
Dry _____	0	0.0	3	2.4	1	1.0	4	3.4
Extension Wells _____								
Successful _____	0	0.0	1	0.9	0	0.0	1	0.9
Dry _____	0	0.0	0	0.0	0	0.0	0	0.0
Exploratory Wells _____								
Successful _____	8	3.8	1	0.5	4	3.3	13	7.5
Dry _____	10	4.7	3	1.8	2	2.0	15	8.5
Total	41	20.1	34	20.5	98	91.4	173	132.0
Wells Acquired ⁽¹⁾ _____	0	0	2	2	12	12	14	14
Wells in Progress at End of Year _____	4	1.1	3	2.17	2	0.75	9	4.02

⁽¹⁾ Includes the acquisition of net interest in wells in which we already held an ownership interest.

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 Eastern region who do not have similar systems or facilities in place. We also believe that our competitive position in the Eastern 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

In 2003, approximately 11% of our total sales were made to one customer. In 2002, approximately 14% of our total sales were made to one customer. In 2002, this customer operated certain properties in which we have interests in the Gulf Coast and purchased all of the production from these wells. This customer would resell the natural gas and oil to third parties with whom we would deal directly if the customer either ceased to exist or stopped buying our portion of the production. In 2001 we had no sales to any customer that exceeded 10% of our total gross revenues.

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. This 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 that 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 ratable 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 we produce and the manner in which our production is transported and marketed. Under the Natural Gas Act of 1938, the FERC regulates the interstate sale for resale of natural gas and the transportation of natural gas in interstate commerce, although facilities used in the production or gathering of natural gas in interstate commerce are exempted from FERC jurisdiction. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated natural gas prices for all "first sales" of natural gas, which includes all sales of our own production. In addition, as part of the broad industry restructuring initiatives described below, the FERC has granted to all producers such as us a "blanket certificate of public convenience and necessity" authorizing the sale of gas for resale without further FERC approvals. 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.

Our natural gas sales prices nevertheless continue to be affected by intrastate and interstate gas transportation regulation, because the prices we receive for our production are affected by the cost of transporting the gas to the consuming market. Through a series of comprehensive rulemakings, beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, the FERC has 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. 436 generally required interstate pipelines to become “open access” transporters of natural gas, thereby requiring pipelines to transport gas supplies owned by others in competition with their own supplies. Order No. 636 further required that interstate pipelines cease making “bundled” sales of natural gas, i.e., gas sales at a single price that includes both the cost of the gas and the cost of its delivery, and further required that pipelines “unbundle” their gathering and transmission services. Order No. 637 has implemented additional requirements to increase the transparency of pricing for pipeline services, including requiring pipelines to implement imbalance management services for shippers; restricting the ability of pipelines to impose penalties for imbalances, overruns, and non-compliance with operational flow orders; and implementing a number of new reporting requirements. The FERC has also developed rules governing the relationship of the pipelines with their marketing affiliates, and implemented 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.

In light of these statutory and regulatory changes, most pipelines have divested their gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants, and most pipelines have also implemented the large-scale divestiture of their gas gathering facilities to affiliated or non-affiliated companies. Interstate pipelines thus now generally provide unbundled, open and nondiscriminatory transportation and transportation-related services to producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking such services. 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.

Certain of 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. In 2002, Congress enacted the Pipeline Safety Improvement Act of 2002, which contains a number of provisions intended to increase pipeline operating safety. The DOT’s final regulations implementing the act became effective in February 2004. Among other provisions, the regulations require that pipeline operators implement a pipeline integrity management program that must at a minimum include an inspection of gas transmission pipeline facilities within the next ten years, and at least every seven years thereafter.

We cannot 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 recent trend toward federal deregulation (or “lighter-handed” regulation) 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, cannot be predicted.

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.

The transition zone and shallow-water areas of the U.S Gulf Coast are ecologically sensitive. Environmental issues have led to higher drilling costs and a more difficult and lengthy well permitting process. U.S. laws and regulations applicable to our operations include those controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment, requiring consistency with applicable coastal zone management plans, or otherwise relating to the protection of the environment.

Outer Continental Shelf Lands Act. The federal Outer Continental Shelf Lands Act (OCSLA) and regulations promulgated pursuant thereto impose a variety of regulations relating to safety and environmental protection applicable to lessees, permits and other parties operating on the Outer Continental Shelf. Specific design and operational standards may apply to Outer Continental Shelf vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to the Outer Continental Shelf Lands Act can result in substantial civil and criminal penalties as well as potential court injunctions curtailing operations and the cancellation of leases. Such enforcement liabilities can result from either governmental or citizen prosecution. We believe that we substantially comply with the OCSLA and its regulations.

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.

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 substantially comply with the Clean Water Act and related federal and state regulations.

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, 2003, Cabot Oil & Gas had 336 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.

Website Access to Company Reports

We make available free of charge through our website, www.cabotog.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission. Information on our website is not a part of this report.

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 the East. At December 31, 2003, we owned or operated approximately 3,200 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.

Wyoming Royalty Litigation

In June 2000, we were sued by two overriding royalty owners in Wyoming state court for unspecified damages. The plaintiffs requested class certification under the Wyoming Rules of Civil Procedure and alleged that we improperly deducted costs of production from royalty payments to the plaintiffs and other similarly situated persons. Additionally, the suit claimed that we failed to properly inform the plaintiffs and other similarly situated persons of the deductions taken from royalties. At a mediation held in April 2003, the plaintiffs in this case claimed total damages of \$9.5 million plus attorney fees. We were recently able to settle the case and the State District Court Judge recently entered his order approving the settlement. The settlement was for a total of \$2.25 million. The class included all private fee royalty and overriding royalty owners of the Company in the State of Wyoming except those in the suit discussed below and one owner who opted out of the settlement. It also includes provisions for the method of valuation of gas for royalty payment purposes going forward and for reporting of royalty payments which should prevent further litigation of these issues by the class members.

In January 2002, 13 overriding royalty owners sued the Company in Wyoming federal district 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. That case is on hold awaiting a Wyoming Supreme Court decision on two certified questions.

Although management believes that a number of our defenses are supported by Wyoming case law, two letter decisions handed down by state district court judges in other cases do not support certain of the defenses. In one of the cases the case has been settled so no order will be entered. In the other case a generic order has been entered adopting the letter decision by reference. It is not known what effect, if any, the decision, will have on the pending case. In addition, in 2000 a district court judge's decision supported our defenses, and that decision was recently orally confirmed by another state district court judge. Accordingly, there is a split of authority concerning the interpretation of the reporting penalty provisions of the Wyoming Royalty Payment Act, which will need to be resolved by the Wyoming Supreme Court.

As noted above, the judge agreed to certify two questions of state law for decision by the Wyoming State Supreme Court. The Wyoming State Supreme Court has agreed to decide both questions, and these decisions should dispose of important issues in the pending federal case. The federal judge refused, however, to certify a question relating to the issue of the proper calculation of damages for failure to provide certain information required by statute on overriding royalty owner check stubs that had been decided adversely to our position in the state district court letter decision. After the federal judge's refusal to certify this issue, the plaintiffs reduced the damages they were claiming. Based upon the plaintiffs expert witness report filed in March 2003, the plaintiffs are now claiming \$21 million in total damages which can be broken down into \$15.7 million for alleged violations of the check stub reporting statute and the remainder for all other damages. In the opinion of our outside counsel, Brown, Drew & Massey, LLP the likelihood of the plaintiffs recovering the stated damages for violation of the check stub reporting statute is remote.

We are vigorously defending the case. We have a reserve that management believes is adequate to provide for the potential liability based on its estimate of the probable outcome of this case. Should circumstances change, the potential impact may materially affect quarterly or annual results of operations and cash flows. However, management does not believe it would materially impact our financial position.

West Virginia Royalty Litigation

In December 2001, we were sued by two royalty owners 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 failed to pay royalty based upon the wholesale market value of the gas produced, that we have taken improper deductions from the royalty and has failed to properly inform the plaintiffs and other similarly situated persons of deductions taken from the royalty. The plaintiffs have also claimed that they are entitled to a 1/8th royalty share of the gas sales contract settlement that we reached with Columbia Gas Transmission Corporation in the 1995 Columbia Gas Transmission Corporation bankruptcy proceeding.

We had removed the lawsuit to federal court; however, in February 2003, we received an order remanding the lawsuit back to state court. Discovery and pleadings necessary to place the class certification issue before the court have been ongoing. A hearing on the plaintiffs' motion for class certification was held on October 20, 2003, and proposed findings

of fact and conclusions of law were submitted to the court on December 5, 2003. The trial is currently scheduled for March 29, 2004. Based on the current status of discovery, the trial date is likely to be continued at a later date.

The investigation into this claim continues and it is in the discovery phase. We are vigorously defending the case. We have reserves we believe are adequate to provide for these potential liabilities based on our estimate of the probable outcome of this matter. Should circumstances change, the potential impact may materially affect quarterly or annual results of operations and cash flows. However, management does not believe it would materially impact our financial position.

Texas Title Litigation

On January 6, 2003, we were served with Plaintiffs' Second Amended Original Petition in Romeo Longoria, et al. v. Exxon Mobil Corporation, et al. in the 79th Judicial District Court of Brooks County, Texas. The plaintiffs allege that they are the rightful owners of a one-half undivided mineral interest in and to certain lands in Brooks County, Texas. As Cody Energy, LLC, the Company acquired certain leases and wells from Wynn-Crosby 1996, Ltd. in 1997 and 1998 and the Company subsequently acquired a 320 acre lease from Hector and Gloria Lopez in 2001. The plaintiffs allege that they are entitled to be declared the rightful owners of an undivided interest in the surface and minerals and all improvements on the lands on which the Company acquired these leases. The plaintiffs also assert claims for trespass to try title, action to remove a cloud on the title, failure to properly account for royalty, fraud, trespass, conversion, all for unspecified actual and exemplary damages. The trial date of May 19, 2003 was cancelled and a new trial date has not been set. We have not had the opportunity to conduct discovery in this matter. We estimate that production revenue from this field since its predecessor, Cody Energy, LLC, acquired title and since we acquired its lease is approximately \$13 million. The carrying value of this property is approximately \$35 million. Co-defendants Shell Oil Company and Shell Western E&P have filed a motion for summary judgment seeking dismissal of plaintiffs' causes of action on multiple grounds. We were in the process of joining in that motion, when the plaintiffs' attorneys asked permission from the Court to withdraw from the representation. The Court granted that request, and new attorneys for some, but not all of the plaintiffs have recently entered the case. The motion for summary judgment was reset and a hearing held in December 2003. The Court has permitted plaintiffs additional time to gather more information, and it is anticipated that the court will hold a second hearing on the motion. We have joined in the motion.

Although the investigation into this claim has just begun, we intend to vigorously defend the case. Management 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 fourth quarter of 2003.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information about our executive officers as of February 15, 2004, 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	Officer Since
Dan O. Dinges	50	Chairman, President and Chief Executive Officer	2001
Michael B. Walen	55	Senior Vice President, Exploration and Production	1998
Scott C. Schroeder	41	Vice President and Chief Financial Officer	1997
J. Scott Arnold	50	Vice President, Land and Associate General Counsel	1998
R. Scott Butler	49	Vice President, Regional Manager, Western Region	2001
Robert G. Drake	56	Vice President, Information Services and Operational Accounting	1998
Abraham D. Garza	57	Vice President, Human Resources	1998
Jeffrey W. Hutton	48	Vice President, Marketing	1995
Thomas S. Liberatore	47	Vice President, Regional Manager, Eastern Region	2003
Lisa A. Machesney	48	Vice President, Managing Counsel and Corporate Secretary	1995
A. F. (Tony) Pelletier	51	Vice President, Regional Manager, Gulf Coast Region	2001
Henry C. Smyth	57	Vice President, Controller and Treasurer	1998

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. He was promoted to his current position of Chairman, President and Chief Executive Officer in May 2002. 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.

Thomas S. Liberatore joined Cabot in January 2002 as Regional Manager, East and was promoted to his current position in July 2003. Prior to joining the Company, Liberatore served as vice president exploration and production for North Coast Energy. He began his career as a geologist and has held various positions of increasing responsibility for Presidio Oil Company and Belden & Blake Corporation. Liberatore received his B.S. in Geology from West Virginia University.

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.

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
2003			
First Quarter	\$29.46	\$24.40	\$ 0.04
Second Quarter	27.96	24.45	0.04
Third Quarter	30.46	26.65	0.04
Fourth Quarter	30.26	25.35	0.04
2002			
First Quarter	\$ 24.95	\$ 18.78	\$ 0.04
Second Quarter	25.82	21.01	0.04
Third Quarter	23.68	18.40	0.04
Fourth Quarter	26.20	20.22	0.04

As of January 30, 2004, there were 761 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.

(In thousands, except per share amounts)	Year Ended December 31,				
	2003	2002	2001	2000	1999
Income Statement Data					
Operating Revenues	\$ 509,391	\$ 353,756	\$ 447,042	\$ 368,651	\$ 294,037
Income from Operations	66,587	49,088	95,366	64,817	39,498
Net Income Available to Common Stockholders	21,132	16,103	47,084	29,221	5,117
Basic Earnings per Share	\$ 0.66	\$ 0.51	\$ 1.56	\$ 1.07	\$ 0.21
Dividends per Common Share	\$ 0.16	\$ 0.16	\$ 0.16	\$ 0.16	\$ 0.16
Balance Sheet Data					
Properties and Equipment, Net	\$ 895,955	\$ 971,754	\$ 981,338	\$ 623,174	\$ 590,301
Total Assets	1,024,201	1,070,929	1,066,777	735,634	659,480
Long-Term Debt	270,000	365,000	393,000	253,000	277,000
Stockholders' Equity	365,197	350,657	346,552	242,505	186,496

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 38.

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

OVERVIEW

Cabot Oil & Gas is a leading independent oil and gas company engaged in the exploration, development and exploitation of natural gas and crude oil from its properties in North America. Our exploration activities are concentrated in areas with known hydrocarbon resources, which are conducive to large, multi-well, repeatable drilling programs and our technical skills. Our program is disciplined and balanced with a focus on achieving strong financial returns.

At Cabot, there are three types of investment alternatives that constantly compete for available capital. These include drilling opportunities, acquisition opportunities and financial opportunities such as debt repayment. Depending on circumstances, we allocate capital among the alternatives based on a rate-of-return approach. Our goal is to invest capital in the highest return opportunities available at any given time.

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. Throughout 2002 and 2003, the NYMEX futures market reported unprecedented natural gas contract prices. Our realized natural gas price was \$4.51 per Mcf in 2003. To lock in these high prices, we entered into a series of crude oil and natural gas price collars and swaps. These financial instruments are an integral element of our risk management strategy but prevented us from realizing the full impact of the price environment.

Commodity prices are impacted by many factors that are outside of our control. Historically, commodity prices have been volatile and we expect them to remain volatile. Commodity prices are affected by changes in market demands, overall

economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas and crude oil prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. In addition to production volumes and commodity prices, finding and developing sufficient amounts of crude oil and natural gas reserves at economical costs are critical to our long-term success.

The tables below illustrate how natural gas prices have fluctuated over the course of 2002 and 2003. "Index" represents the Henry Hub index price per Mmbtu. The "2002" and "2003" price is the natural gas price per Mcf realized by us and it includes the impact of the natural gas price collar or swap arrangements:

Natural Gas Prices by Month - 2003

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	4.96	5.66	9.11	5.14	5.12	5.95	5.30	4.69	4.93	4.44	4.45	4.86
2003	4.33	4.62	4.71	4.48	4.44	4.57	4.65	4.43	4.53	4.33	4.34	4.67

Natural Gas Prices by Month - 2002

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	2.61	2.03	2.39	3.40	3.36	3.37	3.26	2.95	3.27	3.72	4.13	4.13
2002	2.60	2.55	2.44	3.25	2.86	2.86	2.74	2.74	2.83	3.41	3.89	4.17

Prices for crude oil have followed a similar path as the commodity market continued to rise in 2002 and through 2003. The tables below contain the NYMEX average crude oil price (Index) and our realized per Bbl crude oil prices by month for 2002 and 2003.

Crude Oil Prices by Month - 2003

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	32.70	35.73	33.16	28.14	28.07	30.52	30.70	31.60	28.31	30.35	31.06	32.14
2003	29.81	31.47	31.35	29.65	29.18	28.95	30.11	28.82	26.46	27.17	29.43	32.93

(In \$ per Bbl)

Crude Oil Prices by Month - 2002

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	19.43	20.54	24.15	26.02	26.73	25.34	26.73	28.09	29.53	28.71	25.97	29.33
2002	18.56	20.11	22.93	24.27	24.40	23.92	24.14	24.70	26.03	25.57	24.19	25.79

We reported earnings of \$0.66 per share, or \$21.1 million, for 2003. This is up from the \$0.51 per share, or \$16.1 million, reported in 2002. The stronger price environment was the driving factor in this improvement. Prices, including the impact of the hedge arrangements, rose 49% for natural gas and 24% for oil. Substantially offsetting this positive price impact was an after-tax impairment of \$54.4 million related to our Kurten field (see Limited Partnership for discussion of the impairment) and a slight decline in natural gas and crude oil production.

We drilled 173 gross wells with a success rate of 89% in 2003 compared to 108 gross wells with a 93% success rate in 2002. Total capital and exploration expenditures increased \$61.9 million to \$188.2 million in 2003 compared to \$126.3 million for 2002. In previous years, our capital spending, excluding major acquisitions, used substantially all of our operating cash flow. In 2003, our capital and exploration expenditures were under this level, allowing us to reduce debt by \$95.0 million. Our strategy in 2004 is anticipated to remain consistent with 2003. We believe our operating cash flow in 2004 will be sufficient to fund our capital and exploration budgeted spending of \$207.4 million and again provide excess cash flow.

We remain focused on our strategies to grow through the drill bit, balancing the higher risk higher reward exploration opportunities with an extensive development program, and from synergistic acquisitions. We plan to remain disciplined in our capital program while providing for growth potential. 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 38.

FINANCIAL CONDITION

Capital Resources and Liquidity

Our capital resources consist primarily of cash flows from our oil and gas properties and asset-based borrowings supported by our oil and gas reserves. The level of earnings and cash flows depends on many factors, including the price of crude oil and natural gas and our ability to control and reduce costs. Demand for crude oil and natural gas has historically been subject to seasonal influences characterized by peak demand and higher prices in the winter heating season. However, demand and prices moved higher, strengthening from the first half of 2002 into the summer and continued to strengthen through 2003. Prices in 2003 were the result of a higher demand associated with colder than normal winter temperatures, combined with higher storage injection demand in the second and third quarters.

Our primary source of cash during 2003 was from funds generated from operations and proceeds from the sale of certain non-strategic assets. Cash was primarily used to fund exploration and development expenditures, reduce debt and pay dividends. We had a net cash outflow of \$0.9 million during 2003. See below for additional discussion and analysis of cash flow.

	Year Ended December 31,		
	2003	2002	Variance
Cash Flows Provided by Operating Activities	241,638	164,182	77,456
Cash Flows Used by Investing Activities	(151,856)	(138,668)	(13,188)
Cash Flows Used by Financing Activities	(90,660)	(27,364)	(63,296)
Net Decrease in Cash and Cash Equivalents	(878)	(1,850)	972

Cash flow discussion and analysis:

- Cash flows from operating activities increased due to higher commodity prices partially offset by lower natural gas and crude oil production sales volumes. See Results of Operations for a review of the impact of prices and volumes on sales.
- Cash flows used in investing activities increased due to an increase in capital spending and exploration expense.
- Cash flows used in financing activities increased due to additional debt repayments.

The available credit line under our revolving credit 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 bank's petroleum engineer) and other assets. At December 31, 2003, there was no outstanding balance due on the revolving credit facility. The revolving term of the credit facility ends in October 2006. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Management believes that we have the ability to finance through existing available capacity or new debt or equity offerings, if necessary, our capital requirements, including acquisitions.

In the event that the available credit line is adjusted below the outstanding level of borrowings, we have a period of three months to reduce our outstanding debt to the adjusted credit line with a requirement to provide additional borrowing base assets or pay down one-third of the excess during each of the three months.

Our 2004 interest expense is expected to be approximately \$20.0 million.

From time to time we enter into financial instruments to hedge our natural gas and crude oil production prices. While the mark-to-market positions under the hedging agreements will fluctuate with commodity prices, as a producer, our liquidity exposure due to its outstanding derivative instruments tends to increase when commodity prices increase. Consequently, we are most likely to have the largest unfavorable mark-to-market position in a high commodity price environment. At December 31, 2003, the aggregate mark-to-market liability under the aforementioned hedging agreements was \$38.5 million.

Capitalization

Our capitalization information is as follows:

(In millions)	December 31,	
	2003	2002
Debt	\$ 270.0	\$ 365.0
Stockholders' Equity	365.2	350.7
Total Capitalization	\$ 635.2	\$ 715.7
Debt to Capitalization	43%	51%

For the year ended December 31, 2003, we paid dividends of \$5.0 million on our common stock. A regular dividend of \$0.04 per share of common stock has been declared for each quarter since we became a public company.

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, 2003.

(In millions)	2003	2002	2001
Capital Expenditures			
Drilling and Facilities	\$ 102.0	\$ 67.0	\$ 119.5
Leasehold Acquisitions	14.1	4.8	12.9
Pipeline and Gathering	10.6	4.1	3.8
Other	1.8	1.4	1.9
	128.5	77.3	138.1
Proved Property Acquisitions	1.5	8.8 ⁽¹⁾	244.1
Exploration Expense	58.2	40.2	71.2
Total	\$ 188.2	\$ 126.3	\$ 453.4

⁽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.

We plan to drill 276 gross wells in 2004 compared with 173 gross wells drilled in 2003. This 2004 drilling program includes approximately \$207.4 million in total capital and exploration expenditures, up from \$188.2 million in 2003. We will continue to assess the natural gas price environment and may increase or decrease the capital and exploration expenditures accordingly.

There are many factors that impact our depreciation, depletion and amortization rate. These include reserve additions and revisions, development costs, impairments and changes in anticipated production in a future period. In 2004 management expects an increase in our depreciation, depletion and amortization rate due to production declines and reserve revisions on certain wells in south Louisiana. This change may result in an increase of depreciation, depletion and amortization of 10 to 15 percent greater than 2003 levels. This increase will not have an impact on our cash flows.

Contractual Obligations

We are committed to making cash payments in the future on two types of 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, 2003.

(In thousands)	Total	Payments Due by Year			
		2004	2005 to 2006	2007 to 2008	2009 & Beyond
Long-Term Debt	\$ 270,000	\$ —	\$ 40,000	\$ 40,000	\$ 190,000
Operating Leases	19,341	4,650	8,066	6,019	606
Total Contractual Cash Obligations	\$ 289,341	\$ 4,650	\$ 48,066	\$ 46,019	\$ 190,606

Non-GAAP Financial Measures

From time to time management discloses Discretionary Cash Flow and Net Income and Earnings Per Share, excluding selected items. These non-GAAP financial measure calculations may be presented in earnings releases of the Company, furnished in Form 8-K to the Securities and Exchange Commission, along with reconciliations to the most comparable GAAP financial measure for the period.

Discretionary Cash Flow is defined as Net Income plus non-cash charges and Exploration Expense. Discretionary Cash Flow is widely accepted as a financial indicator of an oil and gas company's ability to generate cash which is used to internally fund exploration and development activities, pay dividends and service debt. Discretionary Cash Flow is presented based on management's belief that this non-GAAP measure is helpful to investors when comparing our cash flow with the cash flow of other companies that use the Full Cost method of accounting for oil and gas producing activities or have different financing and capital structures or tax rates. Discretionary Cash Flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating activities, as defined by GAAP, or as a measure of liquidity, or an alternative to Net Income.

Net Income excluding selected items and Earnings Per Share excluding selected items are presented based on management's belief that these non-GAAP measures enable a user of the financial information to understand the impact of these items on reported results. Additionally, this presentation provides a beneficial comparison to similarly adjusted measurements of prior periods. Net Income and Earnings Per Share excluding selected items are not a measure of financial performance under GAAP and should not be considered as an alternative to Net Income and Earnings Per Share, as defined by GAAP.

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.

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. An exploratory dry hole could have a significant effect on the results of operations. 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.

Revenue Recognition

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.

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. The process relies on interpretations of available geologic, geophysics, 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 on 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"*.

Carrying Value of Long-Lived Assets

We perform an impairment analysis whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. Cash flows used in the impairment analysis are determined based upon our estimates of proved crude oil, NGLs and natural gas reserves, future crude oil, NGLs and natural gas prices and costs to extract these reserves. Downward revisions in estimated reserve quantities, increases in future cost estimates or depressed crude oil, NGLs and natural gas prices could cause us to reduce the carrying amounts of its properties.

Costs attributable to our unproved properties are not subject to the impairment analysis described above, however, a portion of the costs associated with such properties is subject to amortization on a composite basis based on past experience and average property lives. As these properties are developed and reserves are proven, the remaining capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year the determination is made. The rate at which the unproved properties are written off depends on the timing and success of the Company's future exploration program.

Accounting for Derivative Instruments and Hedging Activities

Periodically we enter into derivative commodity instruments to hedge our exposure to price fluctuations on natural gas and crude oil production. We follow the accounting prescribed in SFAS 133. 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 com-

ponent 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 were 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.

Long-Term Employee Benefit Costs

Our costs of long-term employee benefits, particularly pension and postretirement benefits, are incurred over long periods of time, and involve many uncertainties over those periods. The net periodic benefit cost attributable to current periods is based on several assumptions about such future uncertainties, and is sensitive to changes in those assumptions. It is management's responsibility, often with the assistance of independent experts, to select assumptions that in its judgment represent best estimates of those uncertainties. It also is management's responsibility to review those assumptions periodically to reflect changes in economic or other factors that affect those assumptions.

The current benefit service costs, as well as the existing liabilities, for pensions and other postretirement benefits are measured on a discounted present value basis. The discount rate is a current rate, related to the rate at which the liabilities could be settled. Our assumed discount rate is based on average rates published for high-quality fixed income securities.

The benefit obligation and the periodic cost of postretirement medical benefits also are measured based on assumed rates of future increase in the per capita cost of covered health care benefits. As of December 31, 2003, the assumed rate of increase was 8.0%. The net periodic cost of pension benefits included in expense also is affected by the expected long-term rate of return on plan assets assumption. The expected return on plan assets rate is normally changed less frequently than the assumed discount rate, and reflects long-term expectations, rather than current fluctuations in market conditions. The actual rate of return on plan assets may differ from the expected rate due to the volatility normally experienced in capital markets. Management's goal is to manage the investments over the long term to achieve optimal returns with an acceptable level of risk and volatility.

Additional information on the key assumptions underlying these benefit costs appears in Note 6 to the Consolidated Financial Statements.

Stock Based Compensation

In accordance with current accounting standards there are two alternative methods that can be used to account for stock-based compensation. The first method is the Intrinsic Value method and recognizes compensation cost as the excess, if any, of the quoted market price of our stock at the grant date over the amount an employee must pay to acquire the stock. The second method is the Fair Value method. Under the fair value method, compensation cost is measured at the grant date based on the value of an award and is recognized over the service period, which is usually the vesting period. Currently, we account for stock-based compensation in accordance with the Intrinsic Value method.

OTHER ISSUES AND CONTINGENCIES

Corporate Income Tax. We generated 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) amounted 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 Eastern 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 was \$1.09 per Mmbtu in 2002. In 1995 and 1996, we completed three transactions to monetize the value of these tax credits, resulting in revenues of \$2.0 million in 2002. The tax credit wells were repurchased in December 2002 and therefore, no monetization revenue was realized in 2003. 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 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, 2003, we are in compliance with all restrictive covenants on both the Revolving Credit Agreement and the Notes. 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.

Limited Partnership. As part of the Cody acquisition, we acquired an interest in certain oil and gas properties in the Kurten field, as general partner of a partnership and as an operator. Prior to the liquidation of the partnership and the divestiture of our interest in the field, we had an interest of approximately 25%, including a one percent interest in the partnership. The liquidation and divestiture was effective July 31 and November 1, respectively, of 2003. Under the partnership agreement, we had the right to a reversionary working interest that would have brought our ultimate interest to 50% upon the limited partner reaching payout. Under the partnership agreement, the limited partner had the option to trigger a liquidation of the partnership. Effective February 13, 2003, the Kurten partnership commenced liquidation at the limited partner's election. In connection with the liquidation, an appraisal was obtained to allocate the interest in the partnership assets. Based on the receipt of the appraisal in February 2003, we would not receive the reversionary interest as part of the liquidation. Due to the impact of the loss of the reversionary interest on future estimated net cash flows of the Kurten field, the limited partner's decision and our decision to proceed with the liquidation, we performed an impairment review which resulted in an after-tax charge of approximately \$54.4 million. This impairment charge is reflected in the 2003 Statement of Operations as an operating expense but did not impact our cash flows.

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 the East.

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*. 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 our 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 with the use of financial instruments. Most recently, we have used financial instruments such as price collar and swap arrangements to reduce the impact of declining prices on our revenue. Under both arrangements, there is also risk that the movement of the index prices will result in the Company not being able to realize the full benefit of a market improvement.

Recently Issued Accounting Pronouncements

In June 2001, the FASB approved for issuance Statement of Financial Accounting Standards (SFAS) 143, *Accounting for Asset Retirement Obligations*. SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (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 adoption of SFAS 143 resulted in (1) an increase of total liabilities, because more retirement obligations are required to be recognized, (2) an increase in the recognized cost of assets, because the retirement costs are added to the carrying amount of the long-lived assets, and (3) an increase in operating expense, because of the accretion of the retirement obligation and additional depreciation and depletion. The majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells. The Company adopted the statement on January 1, 2003. The transition adjustment resulting from the adoption of SFAS 143 has been reported as a cumulative effect of a change in accounting principle in January 2003.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure*. SFAS 148 amends SFAS 123, *Accounting for Stock-Based Compensation*, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on the reported results. The provisions of SFAS 148 are effective for financial statements for fiscal years ending after December 15, 2002.

In January 2003, the FASB issued Financial Interpretation No. 46, *Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51* (FIN 46 or Interpretation). FIN 46 is an interpretation of Accounting Research Bulletin 51, *Consolidated Financial Statements*, and addresses consolidation by business enterprises of variable interest entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. The Interpretation requires an enterprise to consolidate a VIE if that enterprise has a variable interest that will absorb a majority of the entity's expected losses if they occur, receive a majority of the entity's expected residual returns if they occur or both. An enterprise shall consider the rights and obligations conveyed by its variable interests in making this determination. At December 31, 2003 we did not have any entities that would qualify for consolidation in accordance with the provisions of FIN 46. Therefore, the adoption of FIN 46 did not have an impact on our consolidated financial statements.

In April 2003 the FASB issued SFAS 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. SFAS 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities under SFAS 133. The amendments set forth in SFAS 149 require that contracts with comparable characteristics be accounted for similarly. SFAS 149 is generally effective for contracts entered into or modified after June 30, 2003 (with a few exceptions) and for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively only. The adoption of SFAS 149 did not have an impact on our consolidated financial statements.

In May 2003 the FASB issued SFAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This Statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that

is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. This statement was developed in response to concerns expressed by preparers, auditors, regulators, investors, and other users of financial statements about issuers' classification in the statement of financial position of certain financial instruments that have characteristics of both liabilities and equity but that have been presented either entirely as equity or between the liabilities section and the equity section of the statement of financial position. This statement also addresses questions about the classification of certain financial instruments that embody obligations to issue equity shares.

In accordance with SFAS 150, companies with consolidated entities that will terminate by a specified date, such as limited-life partnerships, will have to measure the liabilities for the other owners' interests in those limited-life entities based on the fair values of the limited-life entities' assets. Period-to-period changes in the liabilities are to be reported in the consolidated income statement as interest costs. As a result of SFAS 150, liability amounts and related interest costs may be significantly greater than the minority interests previously recognized. This Statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The adoption of this standard did not have an impact on our consolidated financial statements.

We have been made aware of an issue regarding the application of provisions of SFAS 141, Business Combinations and SFAS No. 142, Goodwill and Other Intangible Assets (SFAS 142) to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS 142 requires registrants to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs. Historically, Cabot and other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties and provided the disclosures required by SFAS No. 69, Disclosures about Oil and Gas Producing Activities (SFAS 69). Also under consideration is whether SFAS 142 requires registrants to provide the additional disclosures prescribed by SFAS 142 for intangible assets for costs associated with mineral rights.

If it is ultimately determined that SFAS 142 requires us to reclassify costs associated with mineral rights from property and equipment to intangible assets, management currently believes that its results of operations and financial condition would not be affected, since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing successful efforts accounting rules and impairment standards. In addition, costs associated with mineral rights would continue to be characterized as oil and gas property costs in our required disclosures under SFAS 69.

At December 31, 2003, we had net undeveloped leaseholds of approximately \$63.0 million that would be classified on our balance sheet as intangible undeveloped leaseholds and developed leaseholds of approximately \$318.4 million (net of accumulated depletion) that would be classified as intangible developed leaseholds if we applied the interpretation currently being discussed.

On December 23, 2003, the FASB issued SFAS 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," an amendment of SFAS 87, 88, and 106, and a revision of SFAS 132. This statement revises employers' disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by SFAS 87, "Employers' Accounting for Pensions," SFAS 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," and SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." The new rules require additional disclosures about the assets, obligations, cash flows, and net periodic benefit cost of defined benefit pension plans and other postretirement benefit plans. The required information should be provided separately for pension plans and for other postretirement benefit plans. The new disclosures are effective for 2003 calendar year financial statements.

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," "will" 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

2003 and 2002 Compared

Net Income and Operating Revenues. We reported net income for the year ended December 31, 2003 of \$21.1 million, or \$0.66 per share. During the corresponding period of 2002, we reported net income of \$16.1 million, or \$0.51 per share. Operating income increased by \$17.5 million compared to the comparable period of the prior year. The increase in net income and operating income was substantially due to an increase in our realized natural gas and crude oil prices.

Natural Gas Production Revenues. The average total company realized natural gas production sales price, including the realized impact of derivative instruments, was \$4.51 per Mcf. Due to derivative instruments this price was reduced by \$0.68 per Mcf. The following table excludes the unrealized impact of the change in derivative fair value for the year ended December 31, 2003 and 2002. These amounts have been included in the Natural Gas Production Revenues line item on the Statement of Operations. See Item 7A for a discussion of the realized and unrealized impact of derivative instruments on operating revenues.

	Year Ended December 31,		Variance	
	2003	2002	Amount	Percent
Natural Gas Production (<i>Mmcf</i>)				
Gulf Coast	29,550	30,408	(857.8)	(3%)
West	23,776	25,308	(1,532.6)	(6%)
East	18,580	17,953	626.3	3%
Total Company	71,906	73,670	(1,764.2)	(2%)
Natural Gas Production Sales Price (<i>\$/Mcf</i>)				
Gulf Coast	\$ 4.78	\$3.34	\$1.44	43%
West	\$ 3.67	\$2.39	\$1.28	54%
East	\$ 5.15	\$3.38	\$1.77	52%
Total Company	\$ 4.51	\$3.02	\$1.49	49%
Natural Gas Production Revenue (<i>In thousands</i>)				
Gulf Coast	\$ 141,107	\$ 101,525	\$ 39,582	39%
West	\$ 87,245	\$ 60,563	\$ 26,682	44%
East	\$ 95,672	\$ 60,696	\$ 34,976	58%
Total Company	\$ 324,024	\$ 222,784	\$ 101,240	45%
Price Variance Impact on Natural Gas Production Revenue				
Gulf Coast	\$ 42,446			
West	\$ 30,349			
East	\$ 32,859			
Total Company	\$ 105,654			
Volume Variance Impact on Natural Gas Production Revenue				
Gulf Coast	\$ (2,864)			
West	\$ (3,667)			
East	\$ 2,117			
Total Company	\$ (4,414)			

The decline in natural gas production is due substantially to the size and timing of Gulf Coast and West drilling program, along with the natural decline of existing production. The increase in the realized natural gas price combined with the decline in production resulted in a net revenue increase of \$101.2 million.

Brokered Natural Gas Revenues and Costs

	Year Ended December 31,		Variance	
	2003	2002	Amount	Percent
Sales Price _____	\$ 5.16	\$ 3.12	\$ 2.04	65%
Volume Brokered _____	18,557	18,807	(250)	(1%)
Brokered Natural Gas Revenues	\$ 95,754	\$ 58,678		
Purchase Price _____	\$ 4.64	\$ 2.82	\$ 1.82	65%
Volume Brokered _____	18,557	18,807	(250)	(1%)
Brokered Natural Gas Cost	\$ 86,104	\$ 53,036		
Brokered Natural Gas Margin <i>(In thousands)</i>	\$ 9,650	\$ 5,642	\$ 4,008	71%
Sales Price Variance Impact on Revenue _____	\$ 37,856			
Volume Variance Impact on Revenue _____	\$ (780)			
	\$ 37,076			
Purchase Price Variance Impact on Purchases _____	\$ (33,774)			
Volume Variance Impact on Purchases _____	\$ 705			
	\$ (33,069)			

Crude Oil and Condensate Revenues. The average total company realized crude oil sales price, including the realized impact of derivative instruments, was \$29.55 per Bbl for the year ended December 31, 2003. Due to derivative instruments this price was reduced by \$1.41 per Bbl. The following table excludes the unrealized impact of the change in derivative fair value for the year ended December 31, 2003 and 2002. These amounts have been included in the Crude Oil and Condensate revenues line item on the Statement of Operations. See Item 7A for a discussion of the realized and unrealized impact of derivative instruments on operating revenues.

	Year Ended December 31,		Variance	
	2003	2002	Amount	Percent
Crude Oil Production (Mbbbl)				
Gulf Coast	2,591	2,620	(30)	(1%)
West	188	216	(27)	(13%)
East	27	33	(6)	(18%)
Total Company	2,806	2,869	(63)	(2%)
Crude Oil Sales Price (\$/Bbl)				
Gulf Coast	\$ 29.48	\$ 23.69	\$ 5.79	24%
West	\$ 30.11	\$ 25.24	\$ 4.87	19%
East	\$ 32.65	\$ 22.09	\$ 10.56	48%
Total Company	\$ 29.55	\$ 23.79	\$ 5.77	24%
Crude Oil Revenue (In thousands)				
Gulf Coast	\$ 76,375	\$ 62,075	\$ 14,299	23%
West	\$ 5,675	\$ 5,445	\$ 230	4%
East	\$ 870	\$ 721	\$ 149	21%
Total Company	\$ 82,919	\$ 68,241	\$ 14,678	22%
Price Variance Impact on Crude Oil Revenue				
Gulf Coast	\$ 14,999			
West	\$ 917			
East	\$ 281			
Total Company	\$ 16,197			
Volume Variance Impact on Crude Oil Revenue				
Gulf Coast	\$ (700)			
West	\$ (687)			
East	\$ (133)			
Total Company	\$ (1,519)			

The decline in crude oil production is due substantially to the size and timing of the Gulf Coast drilling program, along with the natural decline of existing production. The increase in the realized crude oil price combined with the decline in production resulted in a net revenue increase of \$14.6 million.

Other Net Operating Revenues. Other operating revenues increased \$3.6 million. This change was a result of an increase in plant revenue, transportation revenue and natural gas liquid revenue for the year ended December 31, 2003.

Operating Expenses. Total costs and expenses from operations increased \$150.1 million for the year ended December 31, 2003 compared to the year ended December 31, 2002. The primary reasons for this fluctuation are as follows:

- Brokered natural gas cost increased \$33.2 million. For additional information related to this increase see the analysis performed for Brokered Natural Gas Revenue and Cost.

- Exploration expense increased \$18.0 million as a result of higher dry hole expense in 2003. During 2003, we drilled 15 dry exploratory wells compared to 3 in the corresponding period of 2002.
- Impairment of natural gas producing properties expense increased \$91.1 million. This increase is substantially related to a pre-tax non-cash impairment charge of \$87.9 million related to the loss of a reversionary interest in the Kurten field. Effective February 13, 2003, the Kurten partnership commenced liquidation at the limited partner's election. In connection with the liquidation, an appraisal was obtained to allocate the interest in the partnership assets. Based on the receipt of the appraisal in February 2003, we would not receive the reversionary interest as part of the liquidation. Due to the impact of the loss of the reversionary interest on future estimated net cash flows of the Kurten field we performed an impairment review which resulted in an \$87.9 million charge.
- Taxes other than income increased \$12.4 million as a result of higher commodity prices realized in the year ended 2003 as compared to the same period of the prior year.

Interest Expense. Interest expense decreased \$2.4 million. This variance is due to the combination of a lower average level of outstanding debt on the revolving credit facility as well as a decline in interest rates.

Income Tax Expense. Income tax expense increased \$7.4 million due to a comparable increase in our pre-tax net income.

2002 and 2001 Compared

Net Income and Operating Revenues. During 2002, we reported net income of \$16.1 million, or \$0.51 per share. Operating income decreased \$46.3 million and operating revenues decreased \$93.3 million in 2002. The decrease in operating revenues was mainly a result of the \$80.6 million decline in natural gas sales due to the 31% decrease in natural gas prices and the \$32.0 million decrease in brokered natural gas sales revenue, which was also a result of lower prices. Natural gas revenue and our realized price were reduced by \$0.6 million due to hedges in place during 2002. See further discussion in Item 7A. These decreases were partially offset by an increase in crude oil revenue of \$20.0 million due to a 50% increase in the volume of crude oil produced. Operating income was similarly impacted by these revenue changes.

Natural Gas Production Revenues. The average total company realized natural gas production sales price, including the realized impact of derivative instruments, was \$3.02 per Mcf. Due to derivative instruments this price was reduced by \$0.01 per Mcf. The following table excludes the unrealized impact of the change in derivative fair value for the year ended December 31, 2002 and 2001. These amounts have been included in the Natural Gas Production revenues line item on the Statement of Operations. See Item 7A for a discussion of the realized and unrealized impact of derivative instruments on operating revenues.

	Year Ended December 31,		Variance	
	2002	2001	Amount	Percent
Natural Gas Production (Mmcf)				
Gulf Coast	30,408	25,550	4,858	19%
West	25,308	26,167	(859)	(3%)
East	17,953	17,444	509	3%
Total Company	73,670	69,161	4,508	7%
Natural Gas Production Sales Price (\$/Mcf)				
Gulf Coast	\$ 3.34	\$ 4.44	\$ (1.10)	(25%)
West	\$ 2.39	\$ 3.88	\$ (1.49)	(38%)
East	\$ 3.38	\$ 4.96	\$ (1.58)	(32%)
Total Company	\$ 3.02	\$ 4.36	\$ (1.34)	(31%)
Natural Gas Production Revenue (In thousands)				
Gulf Coast	\$ 101,525	\$ 113,443	\$ (11,917)	(11%)
West	\$ 60,563	\$ 101,529	\$ (40,966)	(40%)
East	\$ 60,696	\$ 86,523	\$ (25,827)	(30%)
Total Company	\$ 222,784	\$ 301,494	\$ (78,710)	(26%)
Price Variance Impact on Natural Gas Production Revenue				
Gulf Coast	\$ (33,485)			
West	\$ (37,634)			
East	\$ (28,354)			
Total Company	\$ (99,473)			
Volume Variance Impact on Natural Gas Production Revenue				
Gulf Coast	\$ 21,568			
West	\$ (3,332)			
East	\$ 2,527			
Total Company	\$ 20,763			

The decline in natural gas production is due substantially to the size and timing of Gulf Coast and West drilling program, along with the natural decline of existing production. The increase in the realized natural gas price combined with the decline in production resulted in a net revenue decrease of \$78.7 million.

Brokered Natural Gas Revenues and Costs

	Year Ended December 31,		Variance	
	2002	2001	Amount	Percent
Sales Price _____	\$ 3.12	\$ 4.79	\$ (1.67)	(35%)
Volume Brokered _____	18,807	18,949	(142)	(1%)
Brokered Natural Gas Revenues	\$ 58,678	\$ 90,766		
Purchase Price _____	\$ 2.82	\$ 4.63	\$ (1.81)	(39%)
Volume Brokered _____	18,807	18,949	(142)	(1%)
Brokered Natural Gas Cost	\$ 53,036	\$ 87,734		
Brokered Natural Gas Margin <i>(In thousands)</i>	\$ 5,642	\$ 3,032	\$ 2,610	86%
Sales Price Variance Impact on Revenue _____	\$ (31,408)			
Volume Variance Impact on Revenue _____	\$ (680)			
	\$ (32,088)			
Purchase Price Variance Impact on Purchases _____	\$ 34,041			
Volume Variance Impact on Purchases _____	\$ 657			
	\$ 34,698			

Crude Oil and Condensate Revenues. The average total company realized crude oil sales price, including the realized impact of derivative instruments, was \$23.79 per Bbl for the year ended December 31, 2002. Due to derivative instruments this price was reduced by \$1.81 per Bbl. The following table excludes the unrealized impact of the change in derivative fair value for the year ended December 31, 2002 and 2001. These amounts have been included in the Crude Oil and Condensate revenues line item on the Statement of Operations. See Item 7A for a discussion of the realized and unrealized impact of derivative instruments on operating revenues.

	Year Ended December 31,		Variance	
	2002	2001	Amount	Percent
Crude Oil Production (Mbbbl)				
Gulf Coast _____	2,620	1,621	999	62%
West _____	216	253	(37)	(15%)
East _____	33	35	(2)	(6%)
Total Company	2,869	1,909	960	50%
Crude Oil Sales Price (\$/Bbl)				
Gulf Coast _____	\$ 23.69	\$ 24.78	\$ (1.09)	(4%)
West _____	\$ 25.24	\$ 26.01	\$ (0.77)	(3%)
East _____	\$ 22.09	\$ 23.04	\$ (0.95)	(4%)
Total Company _____	\$ 23.79	\$ 24.91	\$ (1.12)	(4%)
Crude Oil Revenue (In thousands)				
Gulf Coast _____	\$ 62,075	\$ 40,168	\$ 21,907	55%
West _____	\$ 5,445	\$ 6,581	\$ (1,136)	(17%)
East _____	\$ 721	\$ 795	\$ (74)	(9%)
Total Company	\$ 68,241	\$ 47,544	\$ 20,697	44%
Price Variance Impact on Crude Oil Revenue				
Gulf Coast _____	\$ (2,856)			
West _____	\$ (166)			
East _____	\$ (28)			
Total Company	\$ (3,050)			
Volume Variance Impact on Crude Oil Revenue				
Gulf Coast _____	\$ 24,755			
West _____	\$ (962)			
East _____	\$ (46)			
Total Company	\$ 23,747			

The increase in crude oil production is a result of our 2000 and 2001 drilling success in south Louisiana and the acquisition of Cody Company. This increase was slightly offset by a decline in crude oil prices which resulted in a net increase in crude oil revenue of \$20.8 million.

Other Net Operating Revenues. Other operating revenues decreased \$0.7 million to \$6.4 million. In 2002, we provided for payout liabilities on certain properties not operated by us and certain estimated potential legal settlements.

Operating Expenses. Total costs and expenses from operations decreased \$46.8 million, or 13%, from 2001 due primarily to the following:

- Brokered natural gas cost decreased \$34.8 million primarily due to the \$34.1 million impact of decreased natural gas costs per Mcf. Volumes of brokered gas purchases decreased slightly contributing further to a reduction in the amount of \$0.7 million.

- Production and pipeline expense increased \$8.8 million, or 21%, primarily as a result of a full year of costs associated with operating the Cody Company properties acquired in August 2001. Additionally, increased insurance costs and increased drilling activity in the Gulf Coast and Rockies contributed to the rise in expense. On a units-of-production basis, our company-wide production and pipeline expense was \$0.55 per Mcfe in 2002 versus \$0.51 per Mcfe in 2001.
- Exploration expense decreased \$31.0 million primarily as a result of the following:
 - An \$8.9 million decrease in geological and geophysical expenses over last year due to the unusually high 2001 acquisition of seismic data for future evaluation.
 - A \$21.0 million decrease in dry hole costs. In 2002, we drilled nine exploratory wells compared to 27 in 2001. Our success rate on these wells improved from 44% in 2001 to 67% in 2002. The \$16.9 million in dry hole cost recognized in 2002 includes expenditures related to three wells from the 2001 drilling program determined to be dry in 2002, in the amount of \$6.9 million, as well as costs of abandoning certain sections of exploration well bores that were not economical, in the amount of \$3.9 million.
 - A \$0.8 million increase for salaries, wages and related benefits largely attributable to increased staffing in the Gulf Coast region during 2001 to support that year's expanded drilling program and assimilating Cody.
- Depreciation, depletion, amortization and impairment of unproved properties expense increased \$17.4 million, or 20%, over 2001. Natural gas equivalent production increased 12%, increasing DD&A expense by \$11.4 million. The 6% increase in the per unit expense from \$1.09 per Mcfe to \$1.16 per Mcfe was a result of increased production in the higher cost Gulf Coast region (including a full year impact of the newly acquired Cody properties) and resulted in an \$5.6 million increase to DD&A expense for 2001.
- Impairment of Long-Lived Assets decreased by \$4.1 million this year. This year we recorded impairments on four small fields, three of which were in the Gulf Coast and one in the Rocky Mountains. For each of these fields, the capitalized cost exceeded the future undiscounted cash flows. A pipeline in the Eastern region was written down to fair market value. Last year, two fields in the Gulf Coast region were impaired since the cost capitalized exceeded the future undiscounted cash flows. Also in 2001, one natural gas processing plant in the Rocky Mountains area was written down to fair market value. In the fourth quarter of 2001, the Starpath prospect in the Gulf Coast region was impaired.
- General and administrative expenses increased \$2.7 million due to the costs associated with the retirement of the chief executive officer in May 2002.
- Taxes other than income decreased \$3.6 million as a result of lower natural gas and oil revenues.

Interest Expense. Interest expense increased \$4.4 million due to the full year impact of the incremental debt used to partially fund the Cody acquisition in August 2001. Interest expense on the credit facility was down slightly due both to lower levels of borrowings and lower interest rates.

Income Tax Expense. Income tax expense was down \$19.8 million due to the comparable decrease in earnings before income tax. Our effective tax rate decreased slightly in 2002 reflecting a shift of activity between states.

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.

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 and crude oil markets. A hedging committee that consists of members of senior management oversees our hedging activity. Our hedging arrangements apply to only a portion of our production and provide only partial price protection. These hedging arrangements may expose us to risk of financial loss and limit the benefit of increases in prices. Please read the discussion below related to commodity price swaps for a more detailed discussion of our hedging arrangements.

Derivative Instruments and Hedging Activity

Periodically we enter into derivative commodity instruments to hedge our exposure to price fluctuations on natural gas and crude oil production. At December 31, 2003, we had 32 cash flow hedges open: 15 natural gas price collar arrangements and 17 natural gas price swap arrangements. Additionally, we had four crude oil financial instruments and one natural gas financial instrument open at December 31, 2003, that did not qualify for hedge accounting under SFAS 133. At December 31, 2003, a \$33.9 million (\$21.0 million net of tax) unrealized loss was recorded to Other Comprehensive Income, along with a \$39.6 million derivative liability and a \$1.2 million derivative receivable. The change in derivative fair value for the current and prior periods have been included as a component of Natural Gas Production and Crude Oil and Condensate revenue, as appropriate.

The following table summarizes the realized and unrealized impact of derivative activity reflected in the respective line item in Operating Revenues.

	2003		2002		2001	
	Realized	Unrealized	Realized	Unrealized	Realized	Unrealized
Operating Revenues – <i>Increase / (Decrease) to Revenue</i>						
Natural Gas Production	\$ (48,829)	\$ (1,468)	\$ (574)	\$ (1,683)	\$ 33,840	\$ 177
Crude Oil	\$ (3,963)	\$ (1,879)	\$ (5,202)	\$ (693)	\$ —	\$ —

Assuming no change in commodity prices, after December 31, 2003 we would reclassify to earnings, over the next 12 months, \$20.3 million in after-tax expenditures associated with commodity derivatives. This reclassification represents the net liability associated with open positions at December 31, 2003 related to anticipated 2004 production.

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. Under our Revolving Credit Agreement, the aggregate level of commodity hedging must not exceed 80% of the anticipated future equivalent production during the period covered by the hedges. During 2003, natural gas price swaps covered 34,806 Mmcf, or 48% of our gas production, fixing the sales price of this gas at an average of \$4.49 per Mcf.

At December 31, 2003, we had open natural gas price swap contracts covering our 2004 and 2005 production as follows:

Contract Period	Natural Gas Price Swaps		
	Volume in Mmcf	Weighted Average Contract Price	Unrealized Loss (In \$ thousands)
As of December 31, 2003			
<i>Natural Gas Price Swaps on Production in:</i>			
First Quarter 2004	8,017	\$ 5.17	
Second Quarter 2004	7,148	4.99	
Third Quarter 2004	7,226	4.99	
Fourth Quarter 2004	7,226	4.99	
Full Year 2004	29,617	\$ 5.04	\$ 24,610
First Quarter 2005	2,510	\$ 5.13	
Second Quarter 2005	2,537	5.13	
Third Quarter 2005	2,565	5.13	
Fourth Quarter 2005	2,565	5.13	
Full Year 2005	10,177	\$ 5.13	\$ 2,284

From time to time we enter into natural gas and crude oil derivative arrangements that do not qualify for hedge accounting under SFAS 133. These financial instruments are recorded at fair value at the balance sheet date. At December 31, 2003, we had four open crude oil swap arrangements and one natural gas swap arrangement with an unrealized net loss of \$2.6 million and \$0.8 million, respectively, recognized in Operating Revenues.

Hedges on Production - Options

Throughout 2002 and 2003, 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 natural gas and crude oil collars. Under the collar arrangements, if the index price rises above the ceiling price, we pay the counterparty. If the index falls below the floor price, the counterparty pays us.

During 2003, natural gas price collars covered 16,136 Mmcf, or 22% of our gas production, with a weighted average floor of \$4.46 per Mcf and a weighted average ceiling of \$5.41 per Mcf. Additionally, during 2003, we had crude oil price collars which covered 362 Mbbls, or 25% of our production, with a weighted average floor of \$24.75 per bbl and a weighted average ceiling of \$28.86 per bbl. These crude oil contracts expired in June 2003.

At December 31, 2003, we had open natural gas price collar contracts covering our 2004 and 2005 production as follows:

Contract Period	Natural Gas Price Collars		
	Volume in Mmcft	Weighted Average Ceiling / Floor	Unrealized Loss (In \$ thousands)
As of December 31, 2003			
<i>Natural Gas Collars on Production in:</i>			
First Quarter 2004	8,835	\$6.55/\$5.36	
Second Quarter 2004	4,672	\$5.75/\$4.41	
Third Quarter 2004	4,723	\$5.75/\$4.41	
Fourth Quarter 2004	4,723	\$5.75/\$4.41	
Full Year 2004	22,953	\$6.06/\$4.78	\$ 7,447
First Quarter 2005	826	\$5.45/\$4.90	
Second Quarter 2005	836	\$5.45/\$4.90	
Third Quarter 2005	845	\$5.45/\$4.90	
Fourth Quarter 2005	845	\$5.45/\$4.90	
Full Year 2005	3,352	\$5.45/\$4.90	\$ 767

At December 31, 2003, we have no open crude oil price collar arrangements to cover future production.

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.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future market prices of energy commodities. See Forward-Looking Information on page 38.

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. This disclosure is presented in accordance with SFAS 107, "Disclosures about Fair Value of Financial Instruments" and does not impact our financial position, results of operations or cash flows.

LONG-TERM DEBT

	December 31, 2003		December 31, 2002	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
(In thousands)				
Debt				
7.19% Notes	\$ 100,000	\$ 113,673	\$ 100,000	\$ 113,591
7.26% Notes	75,000	87,345	75,000	84,231
7.36% Notes	75,000	87,770	75,000	86,461
7.46% Notes	20,000	24,214	20,000	23,322
Credit Facility	—	—	95,000	95,000
	\$ 270,000	\$ 313,002	\$ 365,000	\$ 402,605

ITEM 8. Financial Statements and Supplementary Data

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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.



Dan O. Dinges
Chairman, President and Chief Executive Officer

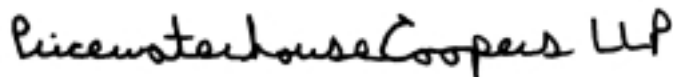
February 16, 2004

REPORT OF INDEPENDENT AUDITORS***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, 2003 and 2002, and the results of their operations, their cash flows and their comprehensive income for each of the three years in the period ended December 31, 2003 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 Notes 1 and 12 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" effective January 1, 2003.

As discussed in Note 11 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, effective January 1, 2001.

A handwritten signature in black ink that reads "PricewaterhouseCoopers LLP". The signature is written in a cursive, flowing style.

Houston, Texas
February 16, 2004

CONSOLIDATED STATEMENT OF OPERATIONS

(In thousands, except per share amounts)

	Year Ended December 31,		
	2003	2002	2001
NET OPERATING REVENUES			
Natural Gas Production	\$ 322,556	\$ 221,101	\$ 301,671
Brokered Natural Gas	95,816	58,729	90,710
Crude Oil and Condensate	81,040	67,548	47,544
Other	9,979	6,378	7,117
	509,391	353,756	447,042
OPERATING EXPENSES			
Brokered Natural Gas Cost	86,162	53,007	87,785
Direct Operations - Field and Pipeline	50,399	50,047	41,217
Exploration	58,119	40,167	71,165
Depreciation, Depletion and Amortization	94,903	96,512	80,619
Impairment of Unproved Properties	9,348	9,348	7,803
Impairment of Long-Lived Assets (Note 14)	93,796	2,720	6,852
General and Administrative	25,112	28,377	27,920
Taxes Other Than Income	37,138	24,734	28,341
	454,977	304,912	351,702
Gain on Sale of Assets	12,173	244	26
INCOME FROM OPERATIONS	66,587	49,088	95,366
Interest Expense and Other	23,545	25,311	20,817
Income Before Income Taxes	43,042	23,777	74,549
Income Tax Expense	15,063	7,674	27,465
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	27,979	16,103	47,084
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX (Note 12)	(6,847)	—	—
NET INCOME	\$ 21,132	\$ 16,103	\$ 47,084
Basic Earnings Per Share - Before Accounting Change	\$ 0.87	\$ 0.51	\$ 1.56
Diluted Earnings Per Share - Before Accounting Change	\$ 0.87	\$ 0.50	\$ 1.53
Basic Loss Per Share - Accounting Change	\$ (0.21)	\$ —	\$ —
Diluted Loss Per Share - Accounting Change	\$ (0.21)	\$ —	\$ —
Basic Earnings Per Share	\$ 0.66	\$ 0.51	\$ 1.56
Diluted Earnings Per Share	\$ 0.65	\$ 0.50	\$ 1.53
Average Common Shares Outstanding	32,050	31,737	30,276
Diluted Common Shares	32,290	32,076	30,684

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

CONSOLIDATED BALANCE SHEET*(In thousands, except share amounts)*

	December 31,	
	2003	2002
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	\$ 724	\$ 1,602
Accounts Receivable	87,425	70,028
Inventories	18,241	15,252
Other	15,006	5,280
Total Current Assets	121,396	92,162
PROPERTIES AND EQUIPMENT, Net (Successful Efforts Method)	895,955	971,754
OTHER ASSETS	6,850	7,013
	\$ 1,024,201	\$ 1,070,929
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	\$ 84,943	\$ 72,619
Accrued Liabilities	69,758	48,312
Total Current Liabilities	154,701	120,931
LONG-TERM DEBT	270,000	365,000
DEFERRED INCOME TAXES	179,926	200,207
OTHER LIABILITIES	54,377	34,134
COMMITMENTS AND CONTINGENCIES (Note 8)		
STOCKHOLDERS' EQUITY		
Common Stock:		
Authorized - 80,000,000 Shares of \$.10 Par Value		
Issued and Outstanding - 32,538,255 Shares and 32,133,118 Shares in 2003 and 2002, Respectively	3,254	3,213
Additional Paid-in Capital	361,699	353,093
Retained Earnings	27,763	11,674
Accumulated Other Comprehensive Loss	(23,135)	(12,939)
Less Treasury Stock, at Cost:		
302,600 Shares in 2003 and 2002	(4,384)	(4,384)
Total Stockholders' Equity	365,197	350,657
	\$ 1,024,201	\$ 1,070,929

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

CONSOLIDATED STATEMENT OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	\$ 21,132	\$ 16,103	\$ 47,084
Adjustments to Reconcile Net Income to Cash			
Provided by Operating Activities:			
Cumulative Effect of Accounting Change	6,847	—	—
Depletion, Depreciation and Amortization	94,903	96,512	80,619
Impairment of Unproved Properties	9,348	9,348	7,803
Impairment of Long-Lived Assets	93,796	2,720	6,852
Deferred Income Tax Expense	(9,837)	7,882	14,157
Gain on Sale of Assets	(12,173)	(244)	(26)
Exploration Expense	58,119	40,167	71,165
Change in Derivative Fair Value	3,347	2,376	(177)
Other	885	3,888	3,030
Changes in Assets and Liabilities:			
Accounts Receivable	(17,397)	(19,317)	34,966
Inventories	(2,989)	2,308	(6,523)
Other Current Assets	(9,208)	3,976	(3,524)
Other Assets	163	(4,307)	(515)
Accounts Payable and Accrued Liabilities	7,041	7,342	(4,894)
Other Liabilities	(2,339)	(4,572)	3,383
Net Cash Provided by Operating Activities	241,638	164,182	253,400
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital Expenditures	(122,018)	(103,189)	(127,129)
Acquisition of Cody Company ⁽¹⁾	—	—	(187,785)
Proceeds from Sale of Assets	28,281	4,688	6,829
Exploration Expense	(58,119)	(40,167)	(71,165)
Net Cash Used by Investing Activities	(151,856)	(138,668)	(379,250)
CASH FLOWS FROM FINANCING ACTIVITIES			
Increase in Short-Term Financing	248,655	180,000	442,481
Decrease in Short-Term Financing	(341,000)	(205,746)	(323,700)
Sale of Common Stock Proceeds	6,728	3,461	7,749
Dividends Paid	(5,043)	(5,079)	(4,802)
Net Cash Provided (Used) by Financing Activities	(90,660)	(27,364)	121,728
Net Decrease in Cash and Cash Equivalents	(878)	(1,850)	(4,122)
Cash and Cash Equivalents, Beginning of Period	1,602	3,452	7,574
Cash and Cash Equivalents, End of Period	\$ 724	\$ 1,602	\$ 3,452

⁽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 of 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.

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY*(In thousands)*

	Common Shares	Stock Par	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income/(Loss)	Retained Earnings (Deficit)	Total
Balance at December 31, 2000	29,494	\$ 2,949	\$ (4,384)	\$ 285,572	\$ —	\$ (41,632)	\$ 242,505
Net Income						47,084	47,084
Exercise of Stock Options	411	42		9,339			9,381
Common Stock Dividends at \$0.16 per Share						(4,802)	(4,802)
Other Comprehensive Income					835		835
Stock Grant Vesting				1,689			1,689
Issuance of Common Stock	2,000	200		49,660			49,860
Balance at December 31, 2001	31,905	\$ 3,191	\$ (4,384)	\$ 346,260	\$ 835	\$ 650	\$ 346,552
Net Income						16,103	16,103
Exercise of Stock Options	209	20		3,845			3,865
Common Stock Dividends at \$0.16 per Share						(5,079)	(5,079)
Other Comprehensive Loss					(13,774)		(13,774)
Stock Grant Vesting	19	2		2,988			2,990
Balance at December 31, 2002	32,133	\$ 3,213	\$ (4,384)	\$ 353,093	\$ (12,939)	\$ 11,674	\$ 350,657
Net Income						21,132	21,132
Exercise of Stock Options	345	35		7,733			7,768
Common Stock Dividends at \$0.16 per Share						(5,043)	(5,043)
Other Comprehensive Loss					(10,196)		(10,196)
Stock Grant Vesting	60	6		873			879
Balance at December 31, 2003	32,538	\$ 3,254	\$ (4,384)	\$ 361,699	\$ (23,135)	\$ 27,763	\$ 365,197

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(In thousands)

	Year Ended December 31,		
	2003	2002	2001
Net Income Available to Common Stockholders	\$ 21,132	\$ 16,103	\$ 47,084
Other Comprehensive (Loss) Income			
Cumulative Effect of Change in Accounting Principle on January 1, 2001	—	—	(4,269)
Reclassification Adjustment for Settled Contracts	47,926	6,230	(32,749)
Changes in Fair Value of Hedge Positions	(63,014)	(26,361)	38,380
Adjustment to Recognize Minimum Pension Liability	(1,333)	(2,177)	—
Foreign Currency Translation Adjustment	(5)	—	—
Deferred Income Tax	6,230	8,534	(527)
Total Other Comprehensive (Loss) Income	(10,196)	(13,774)	835
Comprehensive Income	\$ 10,936	\$ 2,329	\$ 47,919

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

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 almost exclusively within the continental United States.

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

Certain prior year amounts have been reclassified to conform to the current year presentation.

Recently Issued Accounting Pronouncements

In June 2001, the FASB approved for issuance Statement of Financial Accounting Standards (SFAS) 143, "Accounting for Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (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 adoption of SFAS 143 resulted in (1) an increase of total liabilities, because more retirement obligations are required to be recognized, (2) an increase in the recognized cost of assets, because the retirement costs are added to the carrying amount of the long-lived assets, and (3) an increase in operating expense, because of the accretion of the retirement obligation and additional depreciation and depletion. The majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells. The Company adopted the statement on January 1, 2003. The transition adjustment resulting from the adoption of SFAS 143 has been reported as a cumulative effect of a change in accounting principle in January 2003.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." SFAS 148 amends SFAS 123, "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on the reported results. The provisions of SFAS 148 are effective for financial statements for fiscal years ending after December 15, 2002.

In January 2003, the FASB issued Financial Interpretation No. 46, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51" (FIN 46 or Interpretation). FIN 46 is an interpretation of Accounting Research Bulletin 51, "Consolidated Financial Statements," and addresses consolidation by business enterprises of variable interest entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. The Interpretation requires an enterprise to consolidate a VIE if that enterprise has a variable interest that will absorb a majority of the entity's expected losses if they occur, receive a majority of the entity's expected residual returns if they occur or both. An enterprise shall consider the rights and obligations conveyed by its variable interests in making this determination. At December 31, 2003 the Company did not have any entities that would qualify for consolidation in accordance with the provisions of FIN 46. Therefore, the adoption of FIN 46 did not have an impact on the Company's consolidated financial statements.

In April 2003 the FASB issued SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities under SFAS 133. The amendments set forth in SFAS 149 require that contracts with comparable characteristics be accounted for similarly. SFAS 149 is generally effective for contracts entered into or modified after June 30, 2003 (with a few exceptions) and for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively only. The adoption of SFAS 149 did not have an impact on the Company's consolidated financial statements.

In May 2003 the FASB issued SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." This Statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. This Statement was developed in response to concerns expressed by preparers, auditors, regulators, investors, and other users of financial statements about issuers' classification in the statement of financial position of certain financial instruments that have characteristics of both liabilities and equity but that have been presented either entirely as equity or between the liabilities section and the equity section of the statement of financial position. This Statement also addresses questions about the classification of certain financial instruments that embody obligations to issue equity shares.

In accordance with SFAS 150, companies with consolidated entities that will terminate by a specified date, such as limited-life partnerships, will have to measure the liabilities for the other owners' interests in those limited-life entities based on the fair values of the limited-life entities' assets. Period-to-period changes in the liabilities are to be reported in the consolidated income statement as interest costs. As a result of SFAS 150, liability amounts and related interest costs may be significantly greater than the minority interests previously recognized. This Statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The adoption of this standard did not have an impact on the Company's consolidated financial statements.

Management has been made aware of an issue regarding the application of provisions of SFAS 141, Business Combinations and SFAS No. 142, Goodwill and Other Intangible Assets (SFAS 142) to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS 142 requires registrants to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs. Historically, Cabot and other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties and provided the disclosures required by SFAS No. 69, Disclosures about Oil and Gas Producing Activities (SFAS 69). Also under consideration is whether SFAS 142 requires registrants to provide the additional disclosures prescribed by SFAS 142 for intangible assets for costs associated with mineral rights.

If it is ultimately determined that SFAS 142 requires the Company to reclassify costs associated with mineral rights from property and equipment to intangible assets, management currently believes that its results of operations and financial condition would not be affected, since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing successful efforts accounting rules and impairment standards. In addition, costs associated with mineral rights would continue to be characterized as oil and gas property costs in the Company's required disclosures under SFAS 69.

At December 31, 2003, the Company had net undeveloped leaseholds of approximately \$63.0 million that would be classified on its balance sheet as intangible undeveloped leaseholds, and developed leaseholds of approximately \$318.4 million (net of accumulated depletion) that would be classified as intangible developed leaseholds if the Company applied the interpretation currently being discussed.

On December 23, 2003, the FASB issued SFAS 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," an amendment of SFAS 87, 88, and 106, and a revision of SFAS 132. This statement revises employers' disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by SFAS 87, "Employers' Accounting for Pensions," SFAS 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," and SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." The new rules require additional disclosures about the assets, obligations, cash flows, and net periodic benefit cost of defined benefit pension plans and other postretirement benefit plans. The required information should be provided separately for pension plans and for other postretirement benefit plans. The new disclosures are effective for 2003 calendar year financial statements.

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 2002, the Company recorded total impairments of \$2.7 million. In 2003, the Company recorded impairments related to the loss of a reversionary interest in its Kurten field and a field in the East region. These impairments totaled \$93.8 million.

In 2002, the Company recorded impairments on four small fields, three of which were in the Gulf Coast and one in the Rocky Mountains. For each of these fields, the capitalized cost exceeded the future undiscounted cash flows. In addition, a pipeline in the Eastern region was written down to fair market value. 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.

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.

Prior to the adoption of SFAS 143 on January 1, 2003, future estimated plug and abandonment costs were accrued over the productive life of certain oil and gas properties when the residual value of well equipment was not sufficient to cover the plug and abandonment liability. The accrued liability for plug and abandonment costs was included in accumulated depreciation, depletion and amortization. As a component of accumulated depreciation, depletion and amortization, future plug and abandonment costs were \$17.1 million at December 31, 2002 and \$14.4 million at December 31, 2001. The total estimated liability to plug and abandon all wells was \$53.0 million at December 31, 2002 and \$50.8 million at December 31, 2001, excluding the residual value of well equipment. See Note 12, "Adoption of SFAS 143, Accounting for Asset Retirement Obligations", for additional information.

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. See Note 3 for a listing of the Company's liabilities for the current year ended.

Brokered Natural Gas Margin

The revenues and expenses related to brokering natural gas are reported gross as part of Operating Revenues and Operating Expenses. The Company realizes brokered margin as a result of buying and selling natural gas in back-to-back transactions. The Company realized \$9.7 million, \$5.7 million, and \$2.9 million of brokered natural gas margin in 2003, 2002, and 2001, 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. The credit balance included in accounts payable was \$2.7 million at December 31, 2003, which is reflected as an increase in short-term borrowings in financing activities in the Consolidated Statement of Cash Flows. There was no reclassification necessary at December 31, 2002.

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 SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities". 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 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 a 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.

Stock Based Compensation

The Company accounts for stock-based compensation in accordance with the intrinsic value based method recommended by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." Under the intrinsic value based method, compensation cost is the excess, if any, of the quoted market price of the stock at grant date over the amount an employee must pay to acquire the stock.

SFAS 123, "Accounting for Stock-Based Compensation", as amended by SFAS 148, "Accounting for Stock-Based Compensation – Transition and Disclosure", outlines a fair value based method of accounting for stock options or similar equity instruments.

The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS 123 to stock-based employee compensation.

(In thousands, except per share amounts)	Year Ended December 31,		
	2003	2002	2001
Net Income, as reported	\$ 21,132	\$ 16,103	\$ 47,084
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax	1,950	1,605	1,355
Pro forma net income	\$ 19,182	\$ 14,498	\$ 45,729
Earnings per share:			
Basic – as reported	\$ 0.66	\$ 0.51	\$ 1.56
Basic – pro forma	\$ 0.60	\$ 0.46	\$ 1.51
Diluted – as reported	\$ 0.65	\$ 0.50	\$ 1.53
Diluted – pro forma	\$ 0.59	\$ 0.45	\$ 1.49

The assumptions used in the fair value method calculation as well as additional stock based compensation information are disclosed in the following table.

(In thousands, except per share amounts)	Year Ended December 31,		
	2003	2002	2001
Compensation Expense in Net Income, as reported ⁽¹⁾	\$ 1,001	\$ 2,326	\$ 1,078
Weighted Average Value of Options Granted During the Year ⁽²⁾	\$ 6.77	\$ 6.23	\$ 8.61
Assumptions			
Stock Price Volatility	35.3%	35.8%	34.9%
Risk Free Rate of Return	2.5%	3.9%	4.7%
Dividend Rate (Per year)	\$ 0.16	\$ 0.16	\$ 0.16
Expected Term (In years)	4	4	4

⁽¹⁾ Compensation expense is defined as expense related to the vesting of stock grants, net of tax. Compensation expense in 2002 includes \$1.7 million related to the acceleration of stock awards due to the retirement of an executive

⁽²⁾ Calculated using the Black Scholes 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.

Cash and 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, 2003, and 2002, the cash and cash equivalents are primarily concentrated in one financial institution. 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:

<i>(In thousands)</i>	December 31,	
	2003	2002
Unproved Oil and Gas Properties _____	\$ 86,918	\$ 76,959
Proved Oil and Gas Properties _____	1,469,751	1,459,240
Gathering and Pipeline Systems _____	146,909	137,137
Land, Building and Improvements _____	4,758	4,884
Other _____	28,658	29,457
	1,736,994	1,707,677
Accumulated Depreciation, Depletion and Amortization _____	(841,039)	(735,923)
	\$ 895,955	\$ 971,754

During 2003 the Company divested of certain non-strategic assets. These assets include properties in Pennsylvania that were sold for \$16.1 million, and resulted in a gain of \$6.9 million. Additionally, the Company divested of a water treatment facility in the amount of \$3.4 million, which resulted in a gain of \$2.5 million.

Prior to the adoption of SFAS 143 on January 1, 2003, future estimated plug and abandonment costs were accrued over the productive life of certain oil and gas properties when the residual value of well equipment was not sufficient to cover the plug and abandonment liability. The accrued liability for plug and abandonment costs was included in Accumulated Depreciation, Depletion and Amortization. Total future plug and abandonment costs of \$17.1 million and \$1.1 million, recorded at December 31, 2002, have been reclassified from Accumulated Depreciation, Depletion and Amortization and Other Accrued Liabilities, respectively, to Other Long-Term Liabilities due to the adoption of SFAS 143. These reclassifications were made to conform to the current period presentation. See Note 12 for additional discussion regarding the adoption of SFAS 143.

3. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

(In thousands)	December 31,	
	2003	2002
Accounts Receivable		
Trade Accounts	\$ 79,439	\$ 65,796
Joint Interest Accounts	13,312	6,601
Current Income Tax Receivable	—	2,479
Other Accounts	81	619
	92,832	75,495
Allowance for Doubtful Accounts	(5,407)	(5,467)
	\$ 87,425	\$ 70,028
Other Current Assets		
Commodity Hedging Contracts – SFAS 133	\$ 1,152	\$ 634
Drilling Advances	6,443	558
Prepaid Balances	4,325	2,131
Other Accounts	3,086	1,957
	\$ 15,006	\$ 5,280
Accounts Payable		
Trade Accounts	\$ 11,872	\$ 12,358
Natural Gas Purchases	5,751	6,058
Royalty and Other Owners	28,001	20,254
Capital Costs	21,964	13,900
Taxes Other than Income	3,280	3,076
Drilling Advances	5,721	7,254
Wellhead Gas Imbalances	2,085	2,817
Other Accounts	6,269	6,902
	\$ 84,943	\$ 72,619
Accrued Liabilities		
Employee Benefits	\$ 9,105	\$ 8,751
Taxes Other than Income	13,359	9,887
Interest Payable	6,368	7,076
Commodity Hedging Contracts – SFAS 133	36,582	20,680
Other Accounts	4,344	1,918
	\$ 69,758	\$ 48,312
Other Liabilities		
Postretirement Benefits Other than Pension	\$ 2,132	\$ 1,843
Accrued Pension Cost	6,232	8,486
Commodity Hedging Contracts – SFAS 133	3,051	—
Accrued Plugging and Abandonment Liability	36,848	18,151
Taxes Other than Income and Other	6,114	5,654
	\$ 54,377	\$ 34,134

4. Inventories

Inventories are comprised of the following:

(In thousands)	December 31,	
	2003	2002
Natural Gas and Oil in Storage	\$ 15,191	\$ 11,519
Tubular Goods and Well Equipment	3,367	3,334
Pipeline Exchange Balances	(317)	399
	\$ 18,241	\$ 15,252

Natural gas and oil in storage is valued at average cost. Tubular goods and well equipment is valued at historical cost. All inventory balances are carried at the lower of cost or market.

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 required five annual \$16 million principal payments each May starting in 1998. The Company paid the outstanding principal balance of \$32 million, together with accrued interest and a \$0.9 million prepayment penalty (which was recorded as a component of interest expense) in May 2001.

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 in October 2006. 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 reduction in the available credit line, in the event that it is adjusted below the outstanding level of borrowings, the Company has a period of three months to reduce its outstanding debt to the adjusted credit line available with a requirement to provide additional borrowing base assets or pay down one-third of the excess during each of the three months.

Interest rates under the Credit Facility are based on Euro-Dollars (LIBOR) or Base Rate (Prime) indications, plus a margin. These associated margins 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%
Euro-Dollar margin _____	1.250%	1.500%	1.750%
Base Rate margin _____	0.250%	0.500%	0.750%

The Company's effective interest rates for the Credit Facility in the years ended December 31, 2003, 2002, and 2001 were 1.9%, 3.4%, and 7.6%, respectively. The Credit Facility provides for a commitment fee on the unused available balance at an annual rate of three-eighths of 1%. The Credit Facility also contains various customary restrictions, which include the following:

- (a) Maintenance of a minimum asset coverage ratio (present value of proved reserves to debt and other liabilities) that must be at least 1.5 to 1.0,
- (b) 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.
- (c) Prohibition on the merger or sale of all, or substantially all, of the Company's or any subsidiary's assets to a third party, except under certain limited conditions.
- (d) The aggregate level of commodity hedging must not exceed 80% of the anticipated future production during the period covered by the hedges.

The Company was in compliance with all covenants at December 31, 2003 and 2002.

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 measurement date used to measure pension benefit amounts is December 31, 2003.

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 during the last three years are comprised of the following:

<i>(In thousands)</i>	2003	2002	2001
Qualified			
Current Year Service Cost	\$ 1,481	\$ 1,056	\$ 914
Interest Accrued on Pension Obligation	1,515	1,362	1,198
Expected Return on Plan Assets	(999)	(991)	(1,064)
Net Amortization and Deferral	88	88	88
Recognized Loss (Gain)	415	21	(28)
Net Periodic Pension Cost	\$ 2,500	\$ 1,536	\$ 1,108
Non-Qualified			
Current Year Service Cost	\$ 280	\$ 78	\$ 88
Interest Accrued on Pension Obligation	163	29	72
Net Amortization	77	77	77
Loss Recognized from Settlement	—	963	—
Recognized Loss	187	7	21
Net Periodic Pension Cost	\$ 707	\$ 1,154	\$ 258

The following table illustrates the funded status of the Company's pension plans at December 31:

<i>(In thousands)</i>	2003		2002	
	Qualified	Non-Qualified	Qualified	Non-Qualified
Actuarial Present Value of:				
Accumulated Benefit Obligation	\$ 21,347	\$ 3,171	\$ 18,136	\$ 338
Projected Benefit Obligation	\$ 27,411	\$ 6,136	\$ 23,530	\$ 2,511
Plan Assets at Fair Value	18,683	—	10,279	—
Projected Benefit Obligation in Excess of Plan Assets	8,728	6,136	13,251	2,511
Unrecognized Net Loss	(7,083)	(5,457)	(7,283)	(2,462)
Unrecognized Prior Service Cost	(336)	(399)	(424)	(475)
Adjustment to Recognize Minimum Liability	1,355	2,891	2,313	764
Accrued Pension Cost	\$ 2,664	\$ 3,171	\$ 7,857	\$ 338

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:

<i>(In thousands)</i>	2003	2002	2001
Beginning of Year	\$ 26,042	\$ 19,894	\$ 17,151
Service Cost	1,761	1,134	1,002
Interest Cost	1,678	1,391	1,270
Actuarial Loss	4,679	5,860	1,166
Benefits Paid	(613)	(2,237)	(695)
End of Year	\$ 33,547	\$ 26,042	\$ 19,894

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:

<i>(In thousands)</i>	2003	2002	2001
Beginning of Year	\$ 10,279	\$ 9,909	\$ 11,801
Actual Return on Plan Assets	2,446	(1,280)	(1,527)
Employer Contribution	6,735	4,080	584
Benefits Paid	(613)	(2,237)	(695)
Expenses Paid	(164)	(193)	(254)
End of Year	\$ 18,683	\$ 10,279	\$ 9,909

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:

<i>(In thousands)</i>	2003	2002	2001
Funded Status	\$ 14,864	\$ 15,762	\$ 9,985
Unrecognized Gain (Loss)	(12,540)	(9,745)	(2,413)
Unrecognized Prior Service Cost	(735)	(899)	(1,064)
Net Amount Recognized	\$ 1,589	\$ 5,118	\$ 6,508
Accrued Benefit Liability – Qualified Plan	\$ 2,664	\$ 7,857	\$ 6,423
Accrued Benefit Liability – Non-Qualified Plan	3,171	338	816
Intangible Asset	(4,246)	(3,077)	(731)
Net Amount Recognized	\$ 1,589	\$ 5,118	\$ 6,508

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

	2003	2002	2001
Discount Rate ⁽¹⁾	6.25%	6.50%	7.25%
Rate of Increase in Compensation Levels	4.00%	4.00%	4.00%
Long-Term Rate of Return on Plan Assets	8.00%	9.00%	9.00%
Health Care Cost Trend for Medical Benefits	8.00%	8.00%	8.00%

⁽¹⁾ Represents the rate used to determine the benefit obligation. A 6.50% discount rate was used to compute pension costs in 2003, a rate of 7.25% in 2002, and a rate of 7.50% was used in 2001.

The long-term expected rate of return used in 2003 is eight percent. The Company establishes the long-term expected rate of return by developing a forward looking long-term expected rate of return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation.

The plan assets of the Company's qualified and non-qualified pension plans at December 31, 2003 and 2002, by asset category are as follows:

	2003		2002	
<i>(In thousands)</i>	Amount	Percent	Amount	Percent
Equity securities	\$ 11,722	63%	\$ 7,059	69%
Debt securities	3,349	18%	3,012	29%
Other ⁽¹⁾	3,612	19%	208	2%
Total	\$ 18,683	100%	\$ 10,279	100%

⁽¹⁾ Primarily consists of cash and cash equivalents.

The Company's investment strategy for benefit plan assets is to invest in funds to maximize a return over the long-term, subject to an appropriate level of risk, and to achieve a minimum five percent annual real rate of return on the total portfolio. Additionally, the objective of the equity portion of the pension plan assets is to have a rate of return that exceeds the Standard & Poors 500 index by a minimum of two percent annually over the long-term. To achieve these objectives assets are invested with a range of 60 percent to 80 percent equity and 20 percent to 40 percent fixed income.

The funding levels of the pension plans are in compliance with standards set by applicable law or regulation. In 2004 the Company does not have any required minimum funding obligations. Currently, management has not determined if a discretionary funding will be made in 2004.

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 \$1.4 million, \$1.3 million, and \$1.0 million in 2003, 2002, and 2001, respectively. The plan contribution rose in 2003, 2002 and 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, 2003, the balance in the Deferred Compensation Plan's rabbi trust was \$3.6 million.

The employee participants guide the diversification of trust assets. The trust assets are invested in 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 the Company's 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 the Company's 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 244 retirees at the end of 2003 and 246 retirees at the end of 2002. The measurement date used to measure postretirement benefits other than pensions is December 31, 2003.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduces a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to certain Medicare benefits. In accordance with FASB Staff Position 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003, any measures of the accumulated plan benefit obligation or net periodic postretirement benefit cost in the financial statements or accompanying notes do not reflect the effects of the Act on the Company's plan. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require the Company to change previously reported information. Currently, management is considering the impact of this Act on the Company's plan and the possible economic consequences. However, management does not believe the accounting treatment will have a material impact on the consolidated financial statements of the Company.

When the Company adopted SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pension", 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:

<i>(In thousands)</i>	2003	2002	2001
Service Cost of Benefits Earned During the Year	\$ 265	\$ 215	\$ 175
Interest Cost on the Accumulated Postretirement Benefit Obligation	385	381	388
Amortization Benefit of the Unrecognized Gain	(155)	(267)	(291)
Amortization Benefit of the Unrecognized Transition Obligation	662	662	662
Total Postretirement Benefit Cost	\$ 1,157	\$ 991	\$ 934

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 significant future increases in employer cost after 2000.

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

The funded status of the Company's postretirement benefit obligation at December 31, 2003, and 2002 is comprised of the following:

<i>(In thousands)</i>	2003	2002
Plan Assets at Fair Value	\$ —	\$ —
Accumulated Postretirement Benefits Other Than Pensions	6,181	6,185
Unrecognized Cumulative Net Gain	1,736	2,113
Unrecognized Transition Obligation	(5,293)	(5,955)
Accrued Postretirement Benefit Liability	\$ 2,624	\$ 2,343

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

<i>(In thousands)</i>	2003	2002	2001
Beginning of Year	\$ 6,185	\$ 5,507	\$ 5,429
Service Cost	265	215	175
Interest Cost	386	381	388
Actuarial Loss	221	912	265
Benefits Paid	(876)	(830)	(750)
End of Year	\$ 6,181	\$ 6,185	\$ 5,507

7. Income Taxes

Income tax expense is summarized as follows:

(In thousands)	Year Ended December 31,		
	2003	2002	2001
Current			
Federal	\$22,826 ⁽¹⁾	\$ (1,158) ⁽¹⁾	\$10,984 ⁽¹⁾
State	2,075	869	496
Total	24,901	(289)	11,480
Deferred			
Federal	(8,549)	7,931	13,723
State	(1,289)	32	2,262
Total	(9,838)	7,963	15,985
Total Income Tax Expense	\$ 15,063	\$ 7,674	\$27,465

⁽¹⁾ Federal Income Taxes Payable is \$2.7 million at December 31, 2003 and zero at December 31, 2002 and 2001. The zero balances are primarily due to tax payments made during 2002 and 2001 overpayments applied to the current year.

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,		
	2003	2002	2001
Statutory Federal Income Tax Rate	35%	35%	35%
Computed "Expected" Federal Income Tax	\$15,065	\$ 8,322	\$26,092
State Income Tax, Net of Federal Income Tax	1,334	737	2,758
Other, Net	(1,336) ⁽¹⁾	(1,385) ⁽²⁾	(1,385) ⁽³⁾
Total Income Tax Expense	\$15,063	\$ 7,674	\$27,465

⁽¹⁾ Other, Net includes credit adjustments of \$0.8 million related to the recognition of benefit for a state statutory depletion in excess of basis and \$0.5 million related to the recognition of a benefit for a state net operating loss.

⁽²⁾ Other, Net includes credit adjustments totaling \$0.8 million to deferred taxes as a result of a reduction to the state effective tax rate, \$0.8 million to deferred taxes as a result of basis adjustments related to the Cody acquisition, and other permanent items.

⁽³⁾ Other, Net includes credit adjustments totaling \$1.7 million to deferred taxes as a result of a reduction to the state effective tax rate and other permanent items.

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

(In thousands)	2003	2002
Deferred Tax Liabilities		
Property, Plant and Equipment	\$ 208,848	\$ 229,583
Deferred Tax Assets		
Alternative Minimum Tax Credit Carryforwards	—	12,083
Net Operating Loss Carryforwards	725	746
Items Accrued for Financial Reporting Purposes	9,746	8,540
Other Comprehensive Income	18,451	8,007
	28,922	29,376
Net Deferred Tax Liabilities	\$ 179,926	\$ 200,207

As of December 31, 2003, the Company had a net operating loss carryforward of \$14.2 million for state income tax reporting purposes, the majority of which will expire between 2010 and 2018 and none available for regular federal income tax purposes. The Company does not have any alternative minimum tax credit carryforwards available at December 31, 2003 to offset regular income taxes in future years.

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. The lease for the Company's office in Houston runs for approximately six more years. Most of the Company's leases expire within five years and may be renewed. Rent expense under such arrangements totaled \$8.5 million, \$8.8 million, and \$7.7 million for the years ended December 31, 2003, 2002, and 2001, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2003 are as follows:

<i>(In thousands)</i>	
2004	\$ 4,650
2005	4,275
2006	3,791
2007	3,538
2008	2,481
Thereafter	606
	\$ 19,341

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.

Wyoming Royalty Litigation. In June 2000, the Company was sued by two overriding royalty owners in Wyoming state court for unspecified damages. The plaintiffs requested class certification under the Wyoming Rules of Civil Procedure and alleged that the Company improperly deducted costs of production from royalty payments to the plaintiffs and other similarly situated persons. Additionally, the suit claimed that the Company failed to properly inform the plaintiffs and other similarly situated persons of the deductions taken from royalties. At a mediation held in April 2003, the plaintiffs in this case claimed total damages of \$9.5 million plus attorney fees. The Company was recently able to settle the case and the State District Court Judge recently entered his order approving the settlement. The settlement was for a total of \$2.25 million. The class included all private fee royalty and overriding royalty owners of the Company in the State of Wyoming except those in the suit discussed below and one owner who opted out of the settlement. It also includes provisions for the method of valuation of gas for royalty payment purposes going forward and for reporting of royalty payments which should prevent further litigation of these issues by the class members.

In January 2002, 13 overriding royalty owners sued the Company in Wyoming federal district 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. That case is on hold awaiting a Wyoming Supreme Court decision on two certified questions.

Although management believes that a number of the Company's defenses are supported by Wyoming case law, two letter decisions handed down by state district court judges in other cases do not support certain of the defenses. In one of the cases the case has been settled so no order will be entered. In the other case a generic order has been entered adopting the letter decision by reference. It is not known what effect, if any, the decision, will have on the pending case. In addition, in 2000 a district court judge's decision supported the defenses of the Company, and that decision was recently orally confirmed by another state district court judge. Accordingly, there is a split of authority concerning the interpretation of the reporting penalty provisions of the Wyoming Royalty Payment Act, which will need to be resolved by the Wyoming Supreme Court.

As noted above, the judge agreed to certify two questions of state law for decision by the Wyoming State Supreme Court. The Wyoming State Supreme Court has agreed to decide both questions, and these decisions should dispose of important issues in the pending federal case. The federal judge refused, however, to certify a question relating to the issue of the proper calculation of damages for failure to provide certain information required by statute on overriding

royalty owner check stubs that had been decided adversely to the Company's position in the state district court letter decision. After the federal judge's refusal to certify this issue, the plaintiffs reduced the damages they were claiming. Based upon the plaintiffs expert witness report filed in March 2003, the plaintiffs are now claiming \$21 million in total damages which can be broken down into \$15.7 million for alleged violations of the check stub reporting statute and the remainder for all other damages. In the opinion of our outside counsel, Brown, Drew & Massey, LLP the likelihood of the plaintiffs recovering the stated damages for violation of the check stub reporting statute is remote.

The Company is vigorously defending the case. The Company has a reserve that management believes is adequate to provide for the potential liability based on its estimate of the probable outcome of this case. Should circumstances change, the potential impact may materially affect quarterly or annual results of operations and cash flows. However, management does not believe it would materially impact our financial position.

West Virginia Royalty Litigation. In December 2001, the Company was sued by two royalty owners 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 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 has failed to properly inform the plaintiffs and other similarly situated persons of deductions taken from the royalty. The plaintiffs have also claimed that they are entitled to a 1/8th royalty share of the gas sales contract settlement that the Company reached with Columbia Gas Transmission Corporation in the 1995 Columbia Gas Transmission Corporation bankruptcy proceeding.

The Company had removed the lawsuit to federal court; however, in February 2003, we received an order remanding the lawsuit back to state court. Discovery and pleadings necessary to place the class certification issue before the court have been ongoing. A hearing on the plaintiffs' motion for class certification was held on October 20, 2003, and proposed findings of fact and conclusions of law were submitted to the court on December 5, 2003. The trial is currently scheduled for March 29, 2004. Based on the current status of discovery, the trial date is likely to be continued at a later date.

The investigation into this claim continues and it is in the discovery phase. The Company is vigorously defending the case. The Company has reserves it believes are adequate to provide for these potential liabilities based on its estimate of the probable outcome of this matter. Should circumstances change, the potential impact may materially affect quarterly or annual results of operations and cash flows. However, management does not believe it would materially impact the Company's financial position.

Texas Title Litigation. On January 6, 2003, the Company was served with Plaintiffs' Second Amended Original Petition in Romeo Longoria, et al. v. Exxon Mobil Corporation, et al. in the 79th Judicial District Court of Brooks County, Texas. The plaintiffs allege that they are the rightful owners of a one-half undivided mineral interest in and to certain lands in Brooks County, Texas. As Cody Energy, LLC, the Company acquired certain leases and wells from Wynn-Crosby 1996, Ltd. in 1997 and 1998 and the Company subsequently acquired a 320 acre lease from Hector and Gloria Lopez in 2001. The plaintiffs allege that they are entitled to be declared the rightful owners of an undivided interest in the surface and minerals and all improvements on the lands on which the Company acquired these leases. The plaintiffs also assert claims for trespass to try title, action to remove a cloud on the title, failure to properly account for royalty, fraud, trespass, conversion, all for unspecified actual and exemplary damages. The trial date of May 19, 2003 was cancelled and a new trial date has not been set. The Company has not had the opportunity to conduct discovery in this matter. The Company estimates that production revenue from this field since its predecessor, Cody Energy, LLC, acquired title and since the Company acquired its lease is approximately \$13 million. The carrying value of this property is approximately \$35 million. Co-defendants Shell Oil Company and Shell Western E&P have filed a motion for summary judgment seeking dismissal of plaintiffs' causes of action on multiple grounds. The Company was in the process of joining in that motion, when the plaintiffs' attorneys asked permission from the Court to withdraw from the representation. The Court granted that request, and new attorneys for some, but not all of the plaintiffs have recently entered the case. The motion for summary judgment was reset and a hearing held in December 2003. The Court has permitted plaintiffs additional time to gather more information, and it is anticipated that the court will hold a second hearing on the motion. The Company has joined in the motion.

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:

(In thousands)	Year Ended December 31,		
	2003	2002	2001
Interest	\$ 18,298	\$ 25,112	\$ 16,295
Income Taxes	\$ 19,267	\$ 266	\$ 14,395

For the year ended December 31, 2003, the Company recorded a benefit of \$2.7 million for a tax deduction taken due to employee stock option exercises.

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. Under these two 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 4,200,000 shares of Common Stock may be issued under the Incentive Plans. There are no shares available for award under any previous equity plan. All stock options awarded under the Incentive Plans have a maximum term of five years from the date of grant, vesting over time. The options are issued at market value on 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,		
	2003	2002	2001
Shares Under Option at Beginning of Period	1,287,829	1,081,621	1,124,148
Granted	467,000	429,300	454,100
Exercised	345,386	181,027	408,949
Surrendered or Expired	59,942	42,065	87,678
Shares Under Option at End of Period	1,349,501	1,287,829	1,081,621
Options Exercisable at End of Period	511,719	570,406	355,778

For each of the three most recent years, the price range for outstanding options was \$17.44 to \$27.30 per share. The following tables provide more information about the options by exercise price and year.

Options with exercise prices between \$17.44 and \$20.00 per share:

	December 31,		
	2003	2002	2001
Options Outstanding			
Number of Options	444,668	737,385	480,561
Weighted Average Exercise Price	\$ 19.22	\$ 18.97	\$ 17.79
Weighted Average Contractual Term (in years)	2.6	3.0	1.5
Options Exercisable			
Number of Options	204,229	301,277	211,734
Weighted Average Exercise Price	\$ 19.04	\$ 18.39	\$ 17.29

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

	December 31,		
	2003	2002	2001
Options Outstanding			
Number of Options	904,833	550,444	601,060
Weighted Average Exercise Price	\$ 24.69	\$ 25.81	\$ 25.44
Weighted Average Contractual Term (in years)	3.4	3.0	4.3
Options Exercisable			
Number of Options	307,490	269,129	144,044
Weighted Average Exercise Price	\$ 26.42	\$ 25.39	\$ 22.45

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 have been repurchased. The stock repurchase plan was funded from increased borrowings on the revolving credit facility. No treasury shares have been delivered or sold by the Company subsequent to the repurchase.

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% 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% 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, 2003 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.

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. This disclosure is presented in accordance with SFAS 107 "Disclosures about Fair Value of Financial Instruments" and does not impact the Company's financial position, results of operations or cash flows.

Long-Term Debt

	December 31, 2003		December 31, 2002	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
<i>(In thousands)</i>				
Debt				
7.19% Notes	\$ 100,000	\$ 113,673	\$ 100,000	\$ 113,591
7.26% Notes	75,000	87,345	75,000	84,231
7.36% Notes	75,000	87,770	75,000	86,461
7.46% Notes	20,000	24,214	20,000	23,322
Credit Facility	—	—	95,000	95,000
	\$ 270,000	\$ 313,002	\$ 365,000	\$ 402,605

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 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 Credit Facility approximates fair value because this instrument bears interest at rates based on current market rates.

Derivative Instruments and Hedging Activity

The Company periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on natural gas and crude oil production. At December 31, 2003, the Company had 32 cash flow hedges open: 15 natural gas price collar arrangements and 17 natural gas price swap arrangements. Additionally, the Company had four crude oil financial instruments and one natural gas financial instrument open at December 31, 2003, that did not qualify for hedge accounting under SFAS 133. At December 31, 2003, a \$33.9 million (\$21.0 million net of tax) unrealized loss was recorded to Other Comprehensive Income, along with a \$39.6 million derivative liability and a \$1.2 million derivative receivable. The change in derivative fair value for the current and prior periods have been included as a component of Natural Gas Production and Crude Oil and Condensate revenue, as appropriate.

The following table summarizes the realized and unrealized impact of derivative activity reflected in the respective line item in Operating Revenues.

	Year Ended December 31,					
	2003		2002		2001	
	Realized	Unrealized	Realized	Unrealized	Realized	Unrealized
Operating Revenue - <i>Increase/(Decrease) to Revenue</i>						
Natural Gas Production	\$ (48,829)	\$ (1,468)	\$ (574)	\$ (1,683)	\$ 33,840	\$ 177
Crude Oil	\$ (3,963)	\$ (1,879)	\$ (5,202)	\$ (693)	\$ —	\$ —

Assuming no change in commodity prices, after December 31, 2003 the Company would reclassify to earnings, over the next 12 months, \$20.3 million in after-tax expenditures associated with commodity derivatives. This reclassification represents the net liability associated with open positions at December 31, 2003 related to anticipated 2004 production.

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 our 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. Under the Company's Revolving Credit Agreement, the aggregate level of commodity hedging must not exceed 80% of the anticipated future equivalent production during the period covered by the hedges. During 2003, natural gas price swaps covered 34,806 Mmcf, or 48% of our gas production, fixing the sales price of this gas at an average of \$4.49 per Mcf.

At December 31, 2003, the Company had open natural gas price swap contracts covering our 2004 and 2005 production as follows:

Contract Period	Natural Gas Price Swaps		
	Volume in Mmcf	Weighted Average Contract Price	Unrealized Loss (In \$ thousands)
As of December 31, 2003			
<i>Natural Gas Price Swaps on Production in:</i>			
First Quarter of 2004	8,017	\$ 5.17	
Second Quarter of 2004	7,148	4.99	
Third Quarter of 2004	7,226	4.99	
Fourth Quarter of 2004	7,226	4.99	
Full Year of 2004	29,617	\$ 5.04	\$24,610
First Quarter of 2005	2,510	\$ 5.13	
Second Quarter of 2005	2,537	5.13	
Third Quarter of 2005	2,565	5.13	
Fourth Quarter of 2005	2,565	5.13	
Full Year of 2005	10,177	\$ 5.13	\$ 2,284

From time to time the Company enters into natural gas and crude oil derivative arrangements that do not qualify for hedge accounting under SFAS 133. These financial instruments are recorded at fair value at the balance sheet date. At December 31, 2003, the Company had four open crude oil swap arrangements and one natural gas swap arrangement with an unrealized net loss of \$2.6 million and \$0.8 million, respectively, recognized in Operating Revenues.

Hedges on Production - Options

Throughout 2002 and 2003, the Company 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 natural gas and crude oil collars. Under the collar arrangements, if the index price rises above the ceiling price, the Company pays the counterparty. If the index falls below the floor price, the counterparty pays the Company.

During 2003, natural gas price collars covered 16,136 Mmcf, or 22% of the Company's gas production, with a weighted average floor of \$4.46 per Mcf and a weighted average ceiling of \$5.41 per Mcf. Additionally, during 2003, the Company had crude oil price collars which covered 362 Mbbls, or 25% of the Company's production, with a weighted average floor of \$24.75 per bbl and a weighted average ceiling of \$28.86 per bbl. These crude oil contracts expired in June 2003.

At December 31, 2003, the Company had open natural gas price collar contracts covering our 2004 and 2005 production as follows:

Contract Period	Natural Gas Price Collars		
	Volume in Mmcft	Weighted Average Ceiling / Floor	Unrealized Loss (In thousands)
As of December 31, 2003			
<i>Natural Gas Price Collars on Production in:</i>			
First Quarter 2004	8,835	\$ 6.55/\$5.36	
Second Quarter 2004	4,672	\$ 5.75/\$4.41	
Third Quarter 2004	4,723	\$ 5.75/\$4.41	
Fourth Quarter 2004	4,723	\$ 5.75/\$4.41	
Full Year of 2004	22,953	\$6.06/\$4.78	\$ 7,447
First Quarter 2005	826	\$ 5.45/\$4.90	
Second Quarter 2005	836	\$ 5.45/\$4.90	
Third Quarter 2005	845	\$ 5.45/\$4.90	
Fourth Quarter 2005	845	\$ 5.45/\$4.90	
Full Year 2005	3,352	\$5.45/\$4.90	\$ 767

At December 31, 2003, the Company had no open crude oil price collar arrangements to cover future production.

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 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 were 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.

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.

In 2003, approximately 11% of the Company's total sales were made to one customer. In 2002, approximately 14% of the Company's total sales were made to one customer. In 2002, this customer operated certain properties in which the Company has interests in the Gulf Coast and purchased all of the production from these wells. This customer would resell the natural gas and oil to third parties with whom the Company would deal directly if the customer either ceased to exist or stopped buying its portion of the production. In 2001 the Company had no sales to any customer that exceeded 10% of its total gross revenues.

12. Adoption of SFAS 143, "Accounting for Asset Retirement Obligations"

Effective January 1, 2003 the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations." SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method over the assets useful life. The adoption of SFAS 143 resulted in an increase of total

liabilities because additional retirement obligations are required to be recognized, an increase in the recognized cost of assets because the retirement costs are added to the carrying amount of the long-lived asset and an increase in operating expense because of the accretion of the retirement obligation and additional depreciation and depletion. The majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells. However, liabilities will also be recorded for meter stations, pipelines, processing plants and compressors. At December 31, 2003 there are no assets legally restricted for purposes of settling asset retirement obligations. The Company recorded a net-of-tax cumulative effect of change in accounting principle loss, in January of 2003, of approximately \$6.8 million (\$11.0 million before tax) and recorded a retirement obligation of approximately \$35.2 million. There will be no impact on the Company's cash flows as a result of adopting SFAS 143.

Subsequent to the adoption of SFAS 143, there has been no significant current period activity with respect to additional retirement liabilities, settled liabilities, and revisions of estimated cash flows. Additional retirement obligations increase the liability associated with new oil and gas wells and other facilities as these obligations are incurred. Accretion expense for the year-ended December 31, 2003 was \$2.1 million.

The following unaudited pro forma information has been prepared to give effect to the adoption of SFAS 143 as if it had been adopted on January 1, 2002 and January 1, 2001.

(In thousands, except per share amounts)	As of December 31,		
	2003	2002	2001
Net Income	\$ 21,132	\$ 15,077	\$ 46,171
Per Share - Basic	\$ 0.66	\$ 0.48	\$ 1.52
Per Share - Diluted	\$ 0.65	\$ 0.47	\$ 1.50

13. Other Revenue

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 Eastern and Rocky Mountains properties. Due to the repurchase of these tax credit wells in December 2002 there was no monetization revenue realized in 2003. Revenue from these monetized credits was \$2.0 million in 2002 and 2001. The production, revenues, expenses and proved reserves for these properties was reported by the Company as Other Revenue until the credits were repurchased in December 2002. In this repurchase transaction, the Company acquired 26 Bcfe for \$7 million, or \$0.27 per Mcfe. The effective date of the repurchase was December 31, 2002.

14. Acquisition of Cody Company

In August 2001, the Company 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 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 Company recorded a purchase price of approximately \$315.6 million, which was allocated to specific assets and liabilities based on certain estimates of fair value resulting in approximately \$302.4 million allocated to property and \$13.2 million allocated to working capital items. The remaining \$78.0 million of the recorded purchase price reflected a 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 following unaudited pro forma condensed income statement information for the year ended December 31, 2001 has been prepared to give effect to the Cody acquisition as if it had occurred on January 1, 2001.

<i>(In Thousands)</i>	2001
Revenues _____	\$ 505,528
Net Income _____	\$ 54,513
Per share - Basic _____	\$ 1.75
Per share - Diluted _____	\$ 1.73

As part of the Cody acquisition, the Company acquired an interest in certain oil and gas properties in the Kurten field, as general partner of a partnership and as an operator. Prior to the liquidation of the partnership and the divestiture of the Company's interest in the field, it had an interest of approximately 25%, including a one percent interest in the partnership. The liquidation and divestiture was effective July 31 and November 1, respectively, of 2003. The divestiture yielded proceeds of \$7.6 million and resulted in a pre-tax gain of \$1.8 million. Under the partnership agreement, the Company had the right to a reversionary working interest that would have brought its ultimate interest to 50% upon the limited partner reaching payout. Under the partnership agreement, the limited partner had the option to trigger a liquidation of the partnership. Effective February 13, 2003, the Kurten partnership commenced liquidation at the limited partner's election. In connection with the liquidation, an appraisal was obtained to allocate the interest in the partnership assets. Based on the receipt of the appraisal in February 2003, the Company would not receive the reversionary interest as part of the liquidation. Due to the impact of the loss of the reversionary interest on future estimated net cash flows of the Kurten field, the limited partners decision and the Company's decision to proceed with the liquidation, it performed an impairment review which resulted in an after-tax charge of approximately \$54.4 million. This impairment charge is reflected in the 2003 Statement of Operations as an operating expense but did not impact the Company's cash flows.

15. Earnings per Common Share

Basic earnings per common share (EPS) is computed by dividing net income (the numerator) by the weighted average number of common shares outstanding for the period (the denominator). Diluted EPS is similarly calculated using the treasury stock method except that the denominator is increased to reflect the potential dilution that could occur if outstanding stock options and stock awards outstanding at the end of the applicable period were exercised for common stock.

The following is a calculation of basic and diluted weighted average shares outstanding for the year ended December 31, 2003, 2002 and 2001:

		December 31,	
	2003	2002	2001
Shares - Basic _____	32,049,664	31,736,975	30,275,906
Dilution effect of stock options and awards at end of period _____	240,621	338,972	408,361
Shares - Diluted _____	32,290,285	32,075,947	30,684,267
Stock awards and shares excluded from diluted earnings per share due to the anti-dilutive effect _____	965,777	1,174,507	913,310

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, 2003, 2002, and 2001 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 9, 2004, 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, 2003, 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)	2003	2002	2001
Proved Reserves			
Beginning of Year	1,060,959	1,036,004	959,222
Revisions of Prior Estimates	(6,122)	14,405	(44,266)
Extensions, Discoveries and Other Additions	105,497	64,945	99,911
Production	(71,906)	(73,670)	(69,162)
Purchases of Reserves in Place	1,590	26,262	91,290
Sales of Reserves in Place	(20,534)	(6,987)	(991)
End of Year	1,069,484	1,060,959	1,036,004
Proved Developed Reserves	812,280	819,412	804,646
Percentage of Reserves Developed	76.0%	77.2%	77.7%

	Liquids		
	December 31,		
(Thousands of barrels)	2003	2002	2001
Proved Reserves			
Beginning of Year	18,393	19,684	9,914
Revisions of Prior Estimates	307	1,871	254
Extensions, Discoveries and Other Additions	1,723	851	2,257
Production	(2,846)	(2,909)	(1,996)
Purchases of Reserves in Place	—	261	9,255
Sales of Reserves in Place	(5,474)	(1,365)	—
End of Year	12,103	18,393	19,684
Proved Developed Reserves	9,405	13,267	15,328
Percentage of Reserves Developed	77.7%	72.1%	77.9%

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,		
	2003	2002	2001
(In thousands)			
Aggregate Capitalized Costs Relating to Oil and Gas Producing Activities	\$1,732,236	\$1,704,746	\$1,632,101
Aggregate Accumulated Depreciation, Depletion and Amortization	\$ 837,060	\$ 750,857	\$ 651,657

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

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

	Year Ended December 31,		
	2003	2002	2001
(In thousands)			
Property Acquisition Costs, Proved ⁽¹⁾	\$ 1,524	\$ 8,799	\$ 245,079
Property Acquisition Costs, Unproved ⁽¹⁾	14,056	4,869	21,116
Exploration and Extension Well Costs ⁽²⁾	83,147	52,012	91,261
Development Costs	77,006	55,165	90,246
Total Costs	\$ 175,733	\$ 120,845	\$ 447,702

⁽¹⁾ Excludes the \$78.0 million deferred tax gross-up on the Cody acquisition in 2001.

⁽²⁾ Includes administrative exploration costs of \$10,582, \$8,942, and \$9,831 for the years ended December 31, 2003, 2002, and 2001, respectively. These costs are excluded from the Company's calculation of reserve replacement 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,		
	2003	2002	2001
Operating Revenues	\$ 404,503	\$ 280,379	\$ 339,064
Costs and Expenses			
Production	77,315	63,823	58,382
Other Operating	20,090	21,731	22,656
Exploration ⁽¹⁾	58,119	40,167	71,165
Depreciation, Depletion and Amortization	195,659	102,086	89,286
Total Costs and Expenses	351,183	227,807	241,489
Income Before Income Taxes	53,320	52,572	97,575
Provision for Income Taxes	18,662	18,400	34,151
Results of Operations	\$ 34,658	\$ 34,172	\$ 63,424

⁽¹⁾Includes administrative exploration costs of \$10,582, \$8,942, and \$9,831 for the years ended December 31, 2003, 2002, and 2001, respectively. These costs are excluded from the Company's calculation of reserve replacement 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, "Disclosures about Oil and Gas Producing Activities", 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, 2003, 2002, and 2001 for natural gas (\$ per Mcf) were \$5.96, \$4.41, and \$2.65, respectively, and for oil (\$ per Bbl) were \$30.94, \$30.39, and \$18.56, 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,		
	2003 ⁽¹⁾	2002 ⁽¹⁾	2001 ⁽¹⁾
Future Cash Inflows _____	\$ 6,742,214	\$ 5,236,349	\$ 3,107,668
Future Production Costs _____	(1,390,398)	(1,137,615)	(823,988)
Future Development Costs _____	(310,923)	(284,165)	(266,833)
Future Net Cash Flows Before Income Taxes _____	5,040,893	3,814,569	2,016,847
10% Annual Discount for Estimated Timing of Cash Flows _____	(2,844,855)	(2,098,669)	(1,065,747)
Standardized Measure of Discounted Future Net Cash Flows Before Income Taxes _____	2,196,038	1,715,900	951,100
Future Income Tax Expenses, Net of 10% Annual Discount ⁽²⁾ _____	(716,630)	(460,547)	(185,074)
Standardized Measure of Discounted Future Net Cash Flows _____	\$ 1,479,408	\$ 1,255,353	\$ 766,026

⁽¹⁾ Includes the future cash inflows, production costs and development costs, as well as the tax basis, related to the properties.

⁽²⁾ Future income taxes before discount were \$1,800,519, \$1,195,082, and \$558,085 for the years ended December 31, 2003, 2002, and 2001, 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,		
	2003	2002	2001
Beginning of Year _____	\$ 1,255,353	\$ 766,026	\$ 2,409,832
Discoveries and Extensions, Net of Related Future Costs _____	235,079	112,269	100,084
Net Changes in Prices and Production Costs _____	475,026	703,874	(2,545,349)
Accretion of Discount _____	171,590	95,110	353,625
Revisions of Previous Quantity Estimates, Timing and Other _____	(35,691)	51,944	(358,134)
Development Costs Incurred _____	27,529	20,516	26,158
Sales and Transfers, Net of Production Costs _____	(330,800)	(216,555)	(280,682)
Net Purchases (Sales) of Reserves in Place _____	(62,596)	(2,357)	119,149
Net Change in Income Taxes _____	(256,082)	(275,474)	941,343
End of Year _____	\$ 1,479,408	\$ 1,255,353	\$ 766,026

SELECTED DATA (UNAUDITED)

QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

(In thousands, except per share amounts)

	First	Second	Third	Fourth	Total
2003					
Operating Revenues	\$ 135,916	\$ 126,756	\$ 125,471	\$ 121,248	\$ 509,391
Impairment of Long-Lived Assets	87,926	—	5,870	—	93,796
Operating Income	(46,691)	34,850	43,630	34,798	66,587
Net Income (Loss) ⁽¹⁾	(39,223)	17,904	23,220	19,231	21,132
Basic Earnings per Share ⁽¹⁾	\$ (1.23)	\$ 0.56	\$ 0.73	\$ 0.60	\$ 0.66
Diluted Earnings per Share ⁽¹⁾	\$ (1.23)	\$ 0.55	\$ 0.73	\$ 0.60	\$ 0.65

2002

Operating Revenues	\$ 75,073	\$ 89,584	\$ 85,549	\$ 103,550	\$ 353,756
Impairment of Long-Lived Assets	1,063	—	—	1,657	2,720
Operating Income (Loss)	4,996	9,850	15,111	19,131	49,088
Net Income (Loss)	(798)	2,121	6,125	8,655	16,103
Basic Earnings per Share	\$ (0.03)	\$ 0.07	\$ 0.19	\$ 0.27	\$ 0.51
Diluted Earnings per Share	\$ (0.03)	\$ 0.07	\$ 0.19	\$ 0.27	\$ 0.50

⁽¹⁾ Net income reported in Form 10-Q as of September 30, 2003 has been revised to reflect the reversal of the adoption of SFAS 150. This reversal resulted in an increase of \$0.6 million or \$0.02 per common and diluted share for the three months then ended.

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

None.

ITEM 9A. Controls and Procedures

As of the end of December 31, 2003, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the "Exchange Act"). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission's rules and forms, of information required to be disclosed by the issuer in the reports that it files or submits under the Exchange Act.

There have been no significant changes in the Company's internal controls or in other factors that could significantly affect internal controls subsequent to the date the Company carried out its evaluation.

PART III

ITEM 10. Directors and Executive Officers of the Registrant

The information under the caption “Election of Directors”, “Audit Committee” and “Code of Business Conduct” in the Company’s definitive Proxy Statement in connection with the 2004 annual stockholders’ meeting is incorporated by reference.

ITEM 11. Executive Compensation

The information under the caption “Executive Compensation” in the Company’s definitive Proxy Statement in connection with the 2004 annual stockholders’ meeting is incorporated by reference.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Equity Compensation Plan Information

The information under the captions “Beneficial Ownership of Over Five Percent of Common Stock”, “Beneficial Ownership of Directors and Executive Officers”, and “Equity Compensation Plan Information” in the Company’s definitive Proxy Statement in connection with the 2004 annual stockholders’ meeting is incorporated by reference.

ITEM 13. Certain Relationships and Related Transactions

None.

ITEM 14. Principal Accounting Fees and Services

The information under the caption “Fees Billed by Independent Public Accountants for Services in 2003 and 2002” in the Company’s definitive Proxy Statement in connection with the 2004 annual stockholders’ meeting is incorporated by reference.

PART IV

ITEM 15. Exhibits, Financial Statements, Schedules and Reports on Form 8-K

A. INDEX

1. Consolidated Financial Statements

See Index on page 50.

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 (Form 10-K for 2001).
3.3	Certificate of Amendment of Certificate of Incorporation (Form 8-K for July 2, 2002).
3.4	Certificate of Increase of Shares Designated Series A Junior Participating Preferred Stock (Form 8-K for July 2, 2002).
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).
4.7	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).
4.9	Credit Agreement dated as of October 28, 2002 among the Company, the Banks Parties Hereto and Fleet National Bank, as administrative agent (Form 10-Q for the quarter ended September 30, 2002).
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 (Form 10-K for 2001).
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).
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).

Exhibit

Number Description

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- 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 (Form 10-K for 2001).
- 10.16 Second Amended and Restated 1994 Non-Employee Director Stock Option Plan (Form 10-K for 2001).
- 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 (Form 10-K for 2001).
- 10.20 Trust Agreement dated September 2000 between Harris Trust and Savings Bank and the Company (Form 10-K for 2001).
- 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 (Form 10-K for 2001).
- 21.1 Subsidiaries of Cabot Oil & Gas Corporation.
- 23.1 Consent of PricewaterhouseCoopers LLP
- 23.2 Consent of Miller and Lents, Ltd.
- 23.3 Consent of Brown, Drew & Massey, LLP
- 28.1 Miller and Lents, Ltd. Review Letter.
- 31.1 302 Certification – Chairman, President and Chief Executive Officer
- 31.2 302 Certification – Vice President and Chief Financial Officer
- 32.1 906 Certification

B. REPORTS ON FORM 8-K

None.

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 17th of February 2004.

CABOT OIL & GAS CORPORATION

By: /s/ Dan O. Dinges
Dan O. Dinges
Chairman, President and Chief Executive 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
<u>/s/ Dan O. Dinges</u> Dan O. Dinges	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 17, 2004
<u>/s/ Scott C. Schroeder</u> Scott C. Schroeder	Vice President, Chief Financial Officer (Principal Financial Officer)	February 17, 2004
<u>/s/ Henry C. Smyth</u> Henry C. Smyth	Vice President, Controller and Treasurer (Principal Accounting Officer)	February 17, 2004
<u>/s/ Robert F. Bailey</u> Robert F. Bailey	Director	February 17, 2004
<u>/s/ John G. L. Cabot</u> John G. L. Cabot	Director	February 17, 2004
<u>/s/ James G. Floyd</u> James G. Floyd	Director	February 17, 2004
<u>/s/ Robert Kelley</u> Robert Kelley	Director	February 17, 2004
<u>/s/ C. Wayne Nance</u> C. Wayne Nance	Director	February 17, 2004
<u>/s/ P. Dexter Peacock</u> P. Dexter Peacock	Director	February 17, 2004
<u>/s/ William P. Vititoe</u> William P. Vititoe	Director	February 17, 2004

Corporate Information

Officers

Dan O. Dinges

Chairman, President and
Chief Executive Officer

Michael B. Walen

Senior Vice President, Exploration
and Production

Scott C. Schroeder

Vice President and
Chief Financial Officer

J. Scott Arnold

Vice President, Land and
Associate General Counsel

R. Scott Butler

Vice President, Regional Manager,
Western Region

Robert G. Drake

Vice President, Information Services
and Operational Accounting

Abraham D. Garza

Vice President, Human Resources

Jeffrey W. Hutton

Vice President, Marketing

Thomas S. Liberatore

Vice President, Regional Manager,
Eastern Region

Lisa A. Machesney

Vice President, Managing Counsel
and Corporate Secretary

A. F. Pelletier

Vice President, Regional Manager,
Gulf Coast Region

Henry C. Smyth

Vice President, Controller
and Treasurer



Annual Meeting

The annual meeting of the shareholders will be held Thursday, April 29, 2004, at 8:30 a.m. (CDT) at the corporate office in Houston, Texas.

Corporate Office

Cabot Oil & Gas Corporation
1200 Enclave Parkway
Houston, Texas 77077-1607
P. O. Box 4544
Houston, Texas 77210-4544
(281) 589-4600
www.cabotog.com

Independent Auditors

PricewaterhouseCoopers LLP
1201 Louisiana, Suite 2900
Houston, Texas 77002

Reserve Engineers

Miller & Lents, Ltd
Oil & Gas Consultants
1100 Louisiana, 27th Floor
Houston, Texas 77002

Investor Relations

Additional copies of the Form 10-K are available without charge. Shareholders, securities analysts, portfolio managers and others who have questions or need additional information concerning the Company may contact:

Scott C. Schroeder, Vice President
and Chief Financial Officer
(281) 589-4993
scott.schroeder@cabotog.com

Transfer Agent/Registrar

The Bank of New York
Shareholder Relations Department
P. O. Box 11258
Church Street Station
New York, New York 10286
(800) 524-4458
(610) 382-7833 (Outside the U.S.)
(888) 269-5221 (Hearing Impaired -TDD Phone)
shareowners@bankofny.com
www.stockbny.com

Send Certificates for Transfer and Address Changes to:
Receive and Deliver Department
P. O. Box 11002
Church Street Station
New York, New York 10286



Cabot Oil & Gas Corporation

1200 Enclave Parkway Houston, Texas 77077-1607 (281) 589-4600 www.cabotog.com