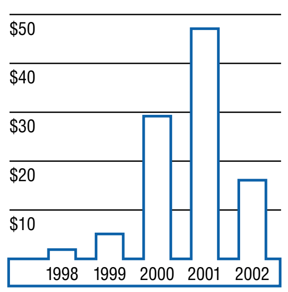
At the Core of Cabot | Stability. Discipline. Integrity.

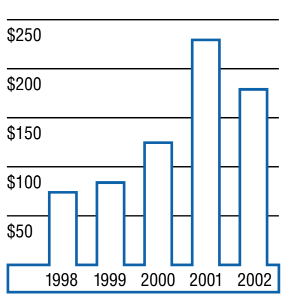
2002 ANNUAL REPORT

Cabot Oil & Gas Corporation

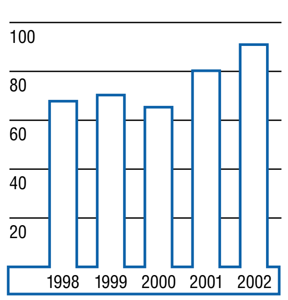
Net Income
(In millions)



Discretionary Cash Flow
(In millions)



Production
(Bcfe)



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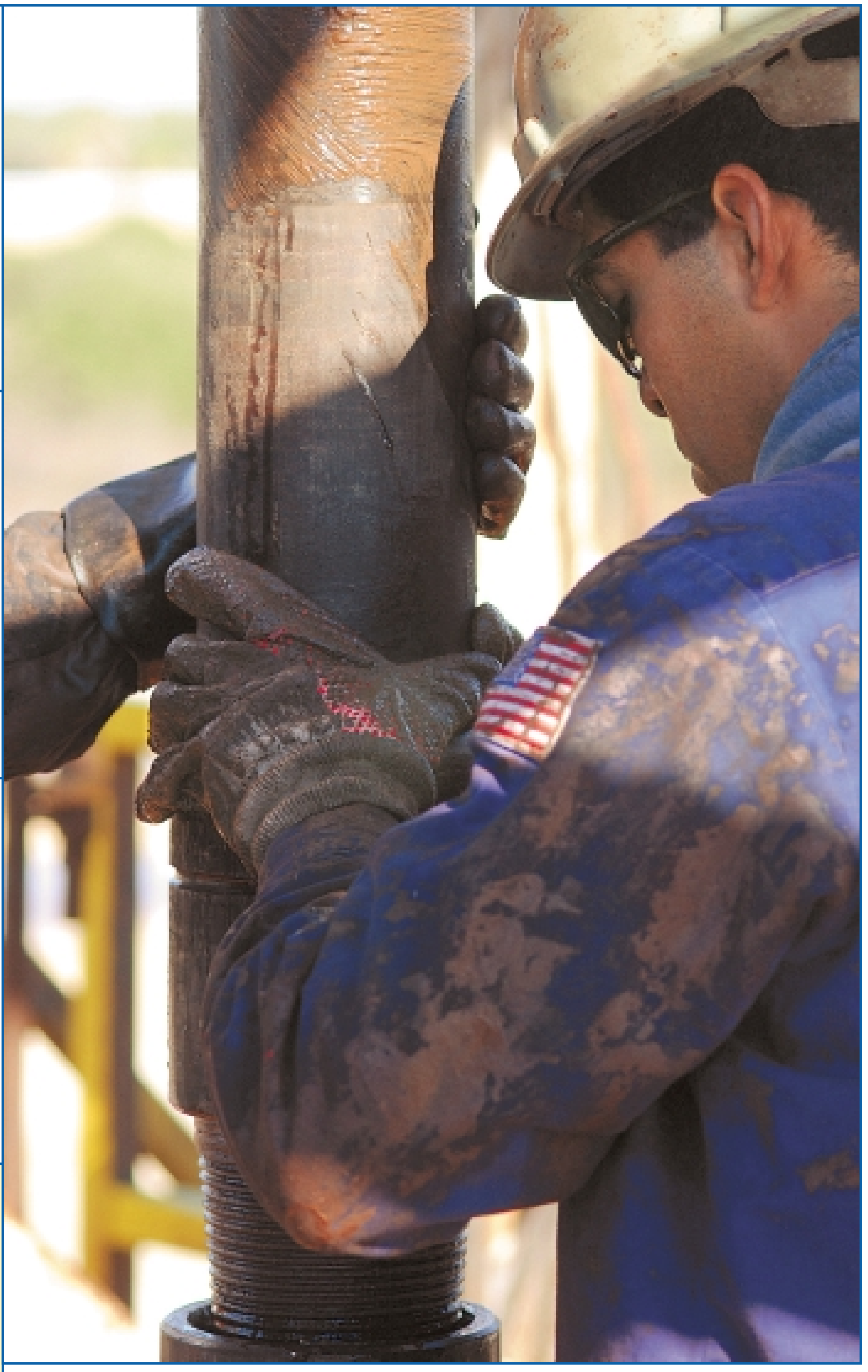

Cabot Oil & Gas Corporation is engaged in the exploration, development, acquisition and exploitation of oil and gas properties. The Company is a leading domestic energy producer with substantial interests in the Texas and Louisiana Gulf Coast, the Western region with operations in the Rocky Mountains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

At the Core of Cabot

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We have developed a distinct set of CORE VALUES that are reflected in our actions for 2002 and in our plans for 2003 to respond to this constant volatility.

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At Cabot, a wide range of criteria are used to evaluate how stable the Company has been in terms of effectively and efficiently utilizing assets and capital for both the short term and long term.

EXPLORATION
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For any company to expand through organic growth a certain level of exploration must be undertaken. This established level, when combined with development drilling, forms the basis for the long-term STABILITY and success of Cabot Oil & Gas.

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By building on experience while exploring new horizons, the Company has set a course to add both offshore and Canadian components to existing core areas.

2003 AND BEYOND
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The future of Cabot Oil & Gas is built on what is accomplished today. Having the DISCIPLINE to maintain a fiscally responsible capital program means finding the right combination of exploration prospects and development drilling opportunities.

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The manner in which Cabot Oil & Gas conducts business is based on the INTEGRITY expected of all employees.

Letter to Shareholders

At the date of this writing I have now served in my capacity as Cabot Oil & Gas Corporation's fourth Chief Executive for nine months. So with that brief tenure I looked back at prior messages to you, the shareholders, and found an obvious but recurring theme regarding the constant state of flux for the industry.

2001 - "one of the most volatile years the industry has seen"
2000 - "the oil and natural gas industry is very cyclical"
1999 - "a challenging operational environment"

As I reviewed these statements, we have developed a distinct set of core values that are reflected in our actions for 2002 and in our plans for 2003 to respond to this constant volatility. Some of these values have been a hallmark of Cabot since inception while others are more recent additions; but we believe each contributes to the Company's road map for success. This annual report is designed to highlight each of these simple but powerful values of stability, discipline and integrity.

In 2002, we continued to reinforce our core values by focusing on our areas of expertise, building a prospect-rich inventory and maintaining a balanced drilling program while looking for opportunistic acquisitions. Our accomplishments for the year included:

- **Increasing production.** In 2002, production grew by over 12 percent year-over-year, driven by the Cody acquisition and results from the Company's drilling program. Of this total, 8 percent was the result of the full-year impact of the Cody acquisition and 4 percent from organic growth.
- **Maintaining profitability.** In a year when natural gas price realizations dropped 31 percent from the prior year, we were able to report net income of $16.1 million and discretionary cash flow of $178.8 million. These levels mark the seventh consecutive year of profitability and the second highest level of cash flow ever generated.
- **Reducing debt.** By maintaining capital discipline as commodity prices increased during the year, total debt decreased $28 million from the prior year.
- **Ensuring financial flexibility.** We negotiated a new $250 million unsecured credit facility with a four-year term.
- **Building prospect inventory.** The Company's two- to three-year prospect inventory includes 78 exploration prospects and leads. Over 40 percent of our prospects and leads are in the Gulf Coast region.
- **Expanding reserves.** Year-end proved reserves increased to 1,171 Bcfe at the end of 2002, compared to 1,154 Bcfe the prior year. Reserve replacement was 136 percent of production on the strength of drilling results and a small acquisition with an "all-in" reserve replacement cost of $.90 per Mcfe.
- **Expanding opportunity.** The Company continued its effort to extend operations into the Gulf of Mexico shelf with the engagement of a generating firm. Also, Cabot initiated efforts in Canada with an exploration joint venture. (See details of the new ventures on page 9.)

With all these positives, a required first quarter non-cash charge announced in February 2003 will squeeze profitability for the year. However, this does not impact our cash flow and will not change our strategic plans.

Moving Forward

As we look into 2003 we have set a course of action that is similar to 2002 in that while we are expanding our capital program, we are not investing all of our anticipated cash flow. Instead, we are again budgeting a reduction in debt to increase our flexibility.

Michael Walen, Senior V.P., Exploration and Production   Dan Dinges, Chairman, President and C.E.O.   Scott Schroeder, V.P. and C.F.O.

- We will continue to focus on areas where we have significant knowledge base, substantial acreage positions and superior drilling opportunities. We will extend our deep transition zone play in south Louisiana onto the Gulf of Mexico shelf and evaluate western Canada as additional growth engines for the Company.
- Our $154 million program in 2003 will allow us to drill 180 wells, including 30 exploration wells (a threefold increase over 2002). The drilling investment totals $89 million. Of this amount, 57 percent is designated for the Gulf Coast, 20 percent for the West and 18 percent for the East.
- We have initiated hedge positions covering 66 percent of our expected 2003 natural gas production at a minimum average price of $4.38 per Mcf, allowing us some level of price protection for our drilling program and ability to reduce debt levels.
- Oil hedges cover 45 percent of our 2003 expected volumes and, like the natural gas hedges, are designed to help lock-in both operational and financial flexibility for the Company.
- We will continue to assess potential acquisitions, but we are aware that making an acquisition in a strong price environment is difficult. Fortunately, Cabot does not need an acquisition for its success.
- Should rig utilization rates begin to climb we will evaluate the best use of our cash flow and determine at that time the effectiveness of maintaining the established drilling program.

Cabot Oil & Gas has been able to reach the level of success today because of our willingness to explore for new prospects while at the same time balancing our program with our legacy assets. We will continue on this path in 2003.

We would like to extend our thanks and gratitude to Board member Henry O. Boswell who will retire in May 2003. As a member of the Company's Board of Directors since 1991, he has made valuable contributions over the years.

As I look back over my first year at Cabot, I continue to see the hallmarks of a Company with tremendous growth opportunities. We have a clear focus on what it takes to be a successful exploration and production company. We have built a successful onshore, and soon to be offshore and Canadian, drilling program with a prospect-rich inventory. In addition, with our high quality assets, talented staff and financial stability, we will be able to continue to deliver value creation for the benefit of our shareholders.

Sincerely,

Dan O. Dinges

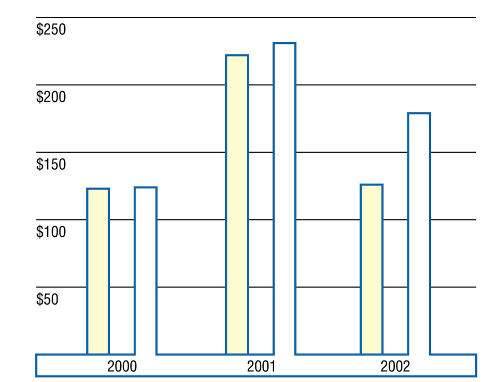
Dan O. Dinges
Chairman, President and Chief Executive Officer

Core Sample

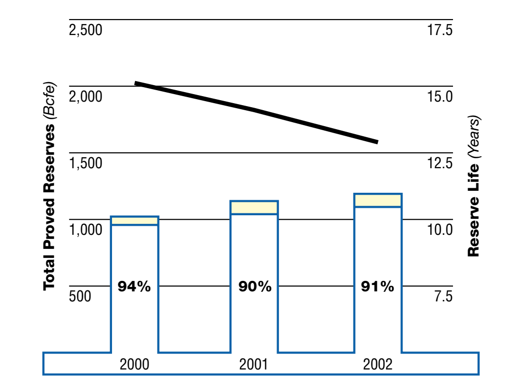
	Year ended December 31,		
	2002	2001	2000
Financial Data *(In millions, except share amounts)*			
Operating Revenues	$ 353.8	$ 447.0	$ 368.7
Net Income Available to Common Shareholders	16.1	47.1	29.2
Per Share	0.51	1.56	1.07
Discretionary Cash Flow [1]	178.8	230.5	124.4
Per Share	5.63	7.61	4.54
Capital and Exploration Expenditures [2]	126.3	453.4	122.6
Common Dividends per Share	$ 0.16	$ 0.16	$ 0.16
Average Common Shares Outstanding *(In thousands)*	31,737	30,276	27,384
Capitalization *(In millions)*			
Long-Term Debt	$ 365.0	$ 393.0	$ 269.0
Shareholders' Equity (Successful Efforts Method)	$ 350.7	$ 346.6	$ 242.5
Annual Production Volume			
Bcfe	91.1	81.1	66.9
% Growth	12%	21%	(6)%
% Gas	81%	85%	91%
Proved Reserves [3]			
Natural Gas *(Bcf)*	1,061.0	1,036.0	959.2
Oil, Condensate and Natural Gas Liquids *(Mmbbl)*	18.4	19.7	9.9
Total Proved *(Bcfe)*	1,171.3	1,154.1	1,018.7
% Gas	91%	90%	94%
% Developed	77%	78%	79%
Reserve Life *(Years)*	12.9	14.2	15.2
Reserve Additions			
Drilling Additions *(Bcfe)*	70.1	113.5	115.8
Drilling Additions, Revisions and Purchases *(Bcfe)*	123.5	217.5	110.2
Reserve Replacement %	136%	268%	165%
Reserve Replacement Cost – Additions *($ per Mcfe)*	$ 1.46	$ 1.70	$ 0.88
Reserve Replacement Cost – Additions, Revisions and Purchases *($ per Mcfe)*	$ 0.90	$ 2.01	$ 0.98
Wells Drilled			
Total Gross	108	208	129
Total Net	72.2	153.6	91.6
Gross Success Rate %	93%	87%	86%
Produced Average Natural Gas Sales Price *($ per Mcf)*			
Gulf Coast	$ 3.34	$ 4.44	$ 3.79
West	2.39	3.88	2.86
East	3.38	4.96	3.24
Total Company	$ 3.02	$ 4.36	$ 3.19
Crude and Condensate Price *($ per Bbl)*	$ 23.79	$ 24.91	$ 26.81

[1] Net income plus non-cash items from operations and exploration expenses less preferred dividends.
[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 79 of this report for details.

Cash Flow vs. Capital Expenditures [1]



Commodity Mix



	Region			
	Gulf Coast	West	East	Total
Annual Production Volumes				
Bcfe	46.3	26.6	18.2	91.1
% of Total	51%	29%	20%	100%
2002 Production *(Mmcfe per day)*	127.0	73.0	49.7	249.7
Gross Wells	900	1,094	2,401	4,395
% Company Operated	79%	66%	97%	86%
Net Developed Acreage	100,861	267,672	741,652	1,110,185
Net Undeveloped Acreage	53,181	373,528	214,351	641,060
Total Net Acreage	154,042	641,200	956,003	1,751,245
Proved Reserves				
Proved Reserves *(Bcfe)*	285.4	430.5	455.4	1,171.3
% of Total	24%	37%	39%	100%
% Developed	70%	83%	75%	77%
Reserve Life *(Years)*	6.2	16.2	25.1	12.9
2002 Capital Program				
Capital Expenditures [2]	$ 69.0	$ 34.0	$ 22.1	$ 126.3
% of Capital Expenditures [2]	55%	27%	17%	100%
Wells Drilled				
Gross	24	40	44	108
Net	12.1	21.3	38.8	72.2
2003 Drilling Program				
% of Drilling Budget [2]	57%	20%	18%	100%
Planned Wells [2]	43	55	82	180

[1] The 2001 capital expenditure amount excludes the $231.2 million cash and stock acquisition of Cody Company.
[2] Administrative and new venture investments are included in the total.

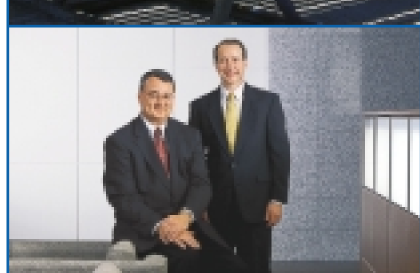
At the Core of Cabot | STABILITY

2002 Year in Review

The stability of a company can be measured numerous ways. At Cabot, a wide range of criteria are used to evaluate how stable the Company has been in terms of effectively and efficiently utilizing assets and capital for both the short term and long term. Principles include gauging the success of the development drilling program, the identification and exploitation of exploration projects, and the implementation of strategic initiatives.

In terms of drilling, past investment in seismic and leasehold plus numerous exploration successes has provided Cabot with a drilling inventory of 78 prospects and leads, dominated by the Gulf Coast region. In addition, close to 400 net proved undeveloped and about 300 probable locations have been identified across the Company, giving Cabot a stable base from which to grow.

Tom Liberatore, Regional Manager, Eastern Region
A. F. Pelletier, V.P., Regional Manager, Gulf Coast Region
R. Scott Butler, V.P., Regional Manager, Western Region



Drilling

In the Gulf Coast region, which in 2002 contributed 127 Mmcfe per day of production, 24 gross wells were drilled, including eight exploratory wells, with a success rate of 83 percent. Currently there are 14 active projects located both onshore and offshore Louisiana, including deep sand projects. Cabot has six active projects onshore Texas, including the Redfish Bay area where to date the Company has an 87 percent drilling success rate.

In the West, Cabot drilled 14 gross wells in the Mid-Continent area and 26 gross wells in the Rocky Mountains, with drilling success rates of 100 percent and 92 percent, respectively. In keeping with the Company's overall philosophy of extending existing plays, Cabot began generating new ideas off existing acreage in the Mid-Continent while expanding acreage, seismic and prospect inventory within the gas dominated plays in the Rocky Mountains.

Cabot drilled 44 gross wells in the East this year with a success rate of 95 percent. Drilling focused primarily on the Pocono and Weir play in southern West Virginia. The Company continues to evaluate its acreage in the Trenton-Black River exploration play. A new initiative in the Danville district, a previously under exploited area, yielded 13 successful wells, adding 3.6 Mmcfe per day to production, at a 100 percent success rate.

J. Scott Arnold, V.P., Land and Associate General Counsel
Jeff Hutton, V.P., Marketing

Gulf Coast: Redfish Bay

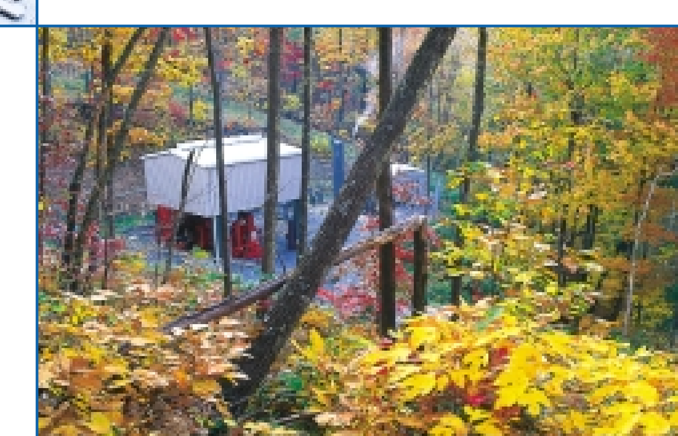
- The Aransas Pass/Redfish Bay area has grown from a deeper pool exploration idea into a significant portion of Cabot's production base, generating 20.5 Mmcfe per day gross (8.2 net) from deeper Frio sands.

West: Mid-Continent

- With a limited drilling program, the Mid-Continent area overcame a 5 percent production decline rate and increased production year-over-year.

West: Rocky Mountains

- Cabot drilled its first high impact wildcat at Wyatt Draw in Wyoming. While the well was unsuccessful, it did confirm the Company's overall structural modeling and supports additional drilling along the Owl Creek thrust fault.
- The Company experienced a 100 percent success rate at its Double Eagle field in the Paradox Basin of southwest Colorado.



East: West Virginia

- The Eastern development drilling program continues to provide a critical balance to the Company's growth plans in other areas.
- Development drilling concentrated in southern West Virginia added an incremental 700 Mmcfe to production year-over-year.

Exploration

For any company to expand through organic growth a certain level of exploration must be undertaken. This established level, when combined with development drilling, forms the basis for the long-term stability and success of Cabot Oil & Gas.

In 2002, the Company experienced several notable exploration successes while concurrently completing a seismic shoot and identifying prospects to be drilled in 2003.

Texas Gulf Coast

- In Redfish Bay, the successful Harbor City wildcat well was completed in May 2002 to a total depth of 15,560 feet and encountered 135 feet of net pay. The neighboring Poblano well, which was finished in February 2002, encountered 96 feet of pay and was drilled to a total depth of 11,499 feet. In early 2003, the wells are producing a combined 8.1 Mmcfe per day net. Potential offsets have been identified from both wells.
- A 53-square mile onshore 3-D seismic shoot was recently completed in a previously unshot portion of the Redfish Bay area, extending (along trend) north and south of Aransas Pass. After data processing is completed, drilling of identified locations should begin by the second half of 2003.

Louisiana Gulf Coast

- The successful Hayworth well, located southwest of New Orleans, targeted the Bourg Sands at approximately 12,000 feet. This 2002 prospect, which completed drilling in January 2003, found 47 feet of net pay sand and is currently being completed. Production is expected in March 2003. Cabot has a 50 percent working interest in the well.
- The DS&B #113 well in the Chacahoula field was successfully completed in the Cypress Sand and is producing 5 Mmcf per day as of March 2003. Cabot has a 100% working interest in the well.

West

- Several basin centered gas plays were identified during 2002, including Rader in the Wind River Basin and Nickey in the Green River Basin. These large prospects will expose Cabot to net unrisked reserve potential of 160 to 180 Bcfe.
- As an extension of the Company's Owl Creek subthrust play, a new high potential prospect at Northwind has been identified. The well has net unrisked reserve potential in excess of 100 Bcfe and will be drilled in late 2003. This prospect was further delineated with information from the Wyatt Draw well.

Strategic Initiatives

By building on experience while exploring new horizons, the Company has set a course to add both offshore and Canadian components to existing core areas. Although implemented in 2002, these strategic initiatives will provide both short-term opportunities and long-term stability for the Company. The impetus for this push into Canada and offshore is the expectation that the future supply of North America's natural gas will come from Canada, Alaska and offshore environments.

These strategic growth initiatives are designed to enhance value by exposing the Company to impact prospects with high production rates.

Expansion of Louisiana Properties

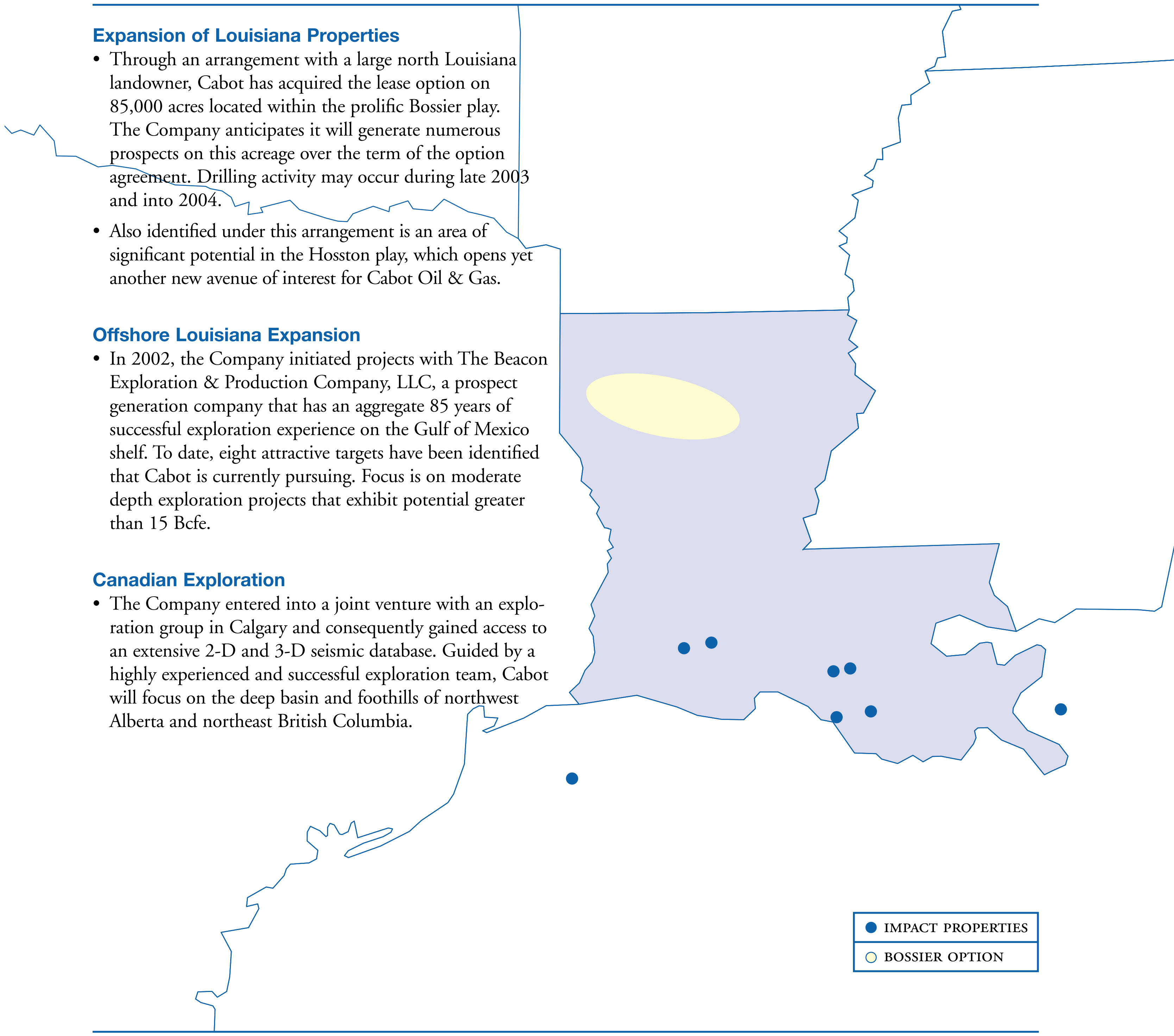
- Through an arrangement with a large north Louisiana landowner, Cabot has acquired the lease option on 85,000 acres located within the prolific Bossier play. The Company anticipates it will generate numerous prospects on this acreage over the term of the option agreement. Drilling activity may occur during late 2003 and into 2004.
- Also identified under this arrangement is an area of significant potential in the Hosston play, which opens yet another new avenue of interest for Cabot Oil & Gas.

Offshore Louisiana Expansion

- In 2002, the Company initiated projects with The Beacon Exploration & Production Company, LLC, a prospect generation company that has an aggregate 85 years of successful exploration experience on the Gulf of Mexico shelf. To date, eight attractive targets have been identified that Cabot is currently pursuing. Focus is on moderate depth exploration projects that exhibit potential greater than 15 Bcfe.

Canadian Exploration

- The Company entered into a joint venture with an exploration group in Calgary and consequently gained access to an extensive 2-D and 3-D seismic database. Guided by a highly experienced and successful exploration team, Cabot will focus on the deep basin and foothills of northwest Alberta and northeast British Columbia.



At the Core of Cabot | Discipline

The future of Cabot Oil & Gas is built on what is accomplished today. Having the discipline to maintain a fiscally responsible capital program means finding the right combination of exploration prospects and development drilling opportunities. Additional activities, which include evaluating acquisitions, securing advantageous hedge positions, retaining an experienced staff and maintaining a sound financial plan, also play vital roles in building shareholder value.

2003 and Beyond

In tandem with the course of action discussed in the Letter to Shareholders, initiatives for 2003 include the following:

Exploration Program

- Economic discipline will be maintained for all exploration projects. The Company has established hurdle rates for each and every project. Rising commodity prices will not change these levels.
- The majority of wildcats the Company plans to drill in 2003 will be in the Gulf Coast region, primarily in south Louisiana (nine wells), south Texas (five wells) and the Gulf of Mexico shelf (four wells). Several high reward/high risk deep wildcats are in the mix.
- Exploration activities in the Rocky Mountains, which include six planned wildcat wells, will continue. The Company is confident that 2003 will yield the exploration success that is paramount for the Rockies program. Emphasis will be placed on large potential prospects, which if successful, will yield growth and visible production overhang.
- All exploration activities will focus where the Company has identified the best opportunities based on balancing the risk with the anticipated return.

Hedging Focus

- The Company has currently hedged 66 percent of its expected natural gas production in 2003. Also for the year, 45 percent of anticipated oil production is covered by either a costless collar or range swap. The natural gas hedges have a minimum average price of $4.38 per Mcf and oil hedges average $27.35 per barrel.
- The natural gas hedges, which have been gradually layered throughout 2002, lock in prices that are at least $1.00 per Mcf above the Company's budgeted project economic hurdle level.

Financial Groundwork

- Given the Company's existing hedge positions and continuing strong commodity prices, further debt reduction is expected in 2003.

Impact of Strategic Initiatives Going Forward

- The Company is expected to grow in terms of acreage inventory, seismic data and prospects.

- An expanded exploration program provides added exposure to impact type opportunities.
- Production and reserve growth is anticipated as a result of successful implementation of the 2003 initiatives.

At the Core of Cabot | Integrity

Just as commodity prices are unpredictable, government response to numerous corporate improprieties continues to unfold. For some companies the impact of the Sarbanes-Oxley Act of 2002 – and regulations yet to be handed down – may be a concern. This has not been the case for Cabot Oil & Gas, which took several steps early on to sustain shareholder confidence in the Company.

Henry Smyth, V.P., Controller and Treasurer*
Lisa Machesney, V.P., Managing Counsel and Corporate Secretary*

Corporate Governance

Separation of Internal and External Audit Functions

- Beginning in February 2002, the Audit Committee agreed to the Company's proposal to engage a new accounting firm to perform internal audits. By August, KPMG, LLP had been engaged to perform all internal audit projects while Cabot retained PricewaterhouseCoopers LLP for external audit responsibilities.

Establishment of a Disclosure Committee

- This Committee created a formal information flow throughout and up the organization. Its members are four officers of the Company who have experience in varied disciplines, including legal, financial, risk management, marketing and operations. Any material findings are reported directly to the Chief Executive Officer and Chief Financial Officer.

**Co-chair of Disclosure Committee*

Independence - Reinforced

- Since May 2002, the only insider on the Board of Directors is the Chairman, President and Chief Executive Officer. No former officers are on the Board.
- The Audit and Nominations/Corporate Governance Committees, along with the Compensation Subcommittee of the Board are comprised of all independent directors.
- A financial expert, as recently defined by the SEC, already exists on the Audit Committee.

The manner in which Cabot Oil & Gas conducts business is based on the integrity expected of all employees. Over the years the Company has maintained a transparent corporate structure that is inherently designed to enhance shareholder value while adhering to strict business conduct and financial principles. The initiatives launched in 2002 simply formalize many of the aspects of the exploration and production business already in use at Cabot Oil & Gas.

Board of Directors

Committees

Audit Committee
Henry O. Boswell – *Chairman*
Robert F. Bailey
John G.L. Cabot
P. Dexter Peacock

Compensation Committee
C. Wayne Nance – *Chairman*
Henry O. Boswell
Arthur L. Smith
William P. Vititoe

Compensation Subcommittee
C. Wayne Nance – *Chairman*
Henry O. Boswell
William P. Vititoe

Executive Committee
P. Dexter Peacock – *Chairman*
Henry O. Boswell
Dan O. Dinges
C. Wayne Nance

Nominations/Corporate Governance Committee
James G. Floyd – *Chairman*
C. Wayne Nance
P. Dexter Peacock
William P. Vititoe

Safety & Environmental
John G.L. Cabot – *Chairman*
Robert F. Bailey
James G. Floyd
Arthur L. Smith

Directors

Dan O. Dinges
Chairman of the Board,
President and
Chief Executive Officer

Robert F. Bailey
Investor – Private oil and
gas interests
Former President and
Chief Executive Officer,
TransRepublic Resources, Inc.

Henry O. Boswell
Former President,
Amoco Production Company

John G.L. Cabot
Former Vice Chairman of the Board
and Chief Financial Officer,
Cabot Corporation

James G. Floyd
Former Chief Executive Officer
and Director, The Houston
Exploration Company

C. Wayne Nance
Senior Vice President,
The Mitchell Group
Former President,
Tenneco Oil Company

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

Arthur L. Smith
Chairman and Chief Executive
Officer, John S. Herold, Inc.

William P. Vititoe
Former Chairman of the Board
and Chief Executive Officer,
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, 2002**

Commission file number 1-10447

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

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

Title of each class	Name of each exchange on which registered
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 January 31, 2003), was approximately $749,100,000. As of January 31, 2003, there were 32,133,975 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, 2003 are incorporated herein by reference in Items 10, 11, 12 and 13 of Part III of this report.

TABLE OF CONTENTS

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 for future drilling and marketing activity, future production and costs, and other factors detailed in this document and in our other Securities and Exchange Commission filings. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual outcomes may vary materially from those included in this document.

Part I

ITEM 1. Business

OVERVIEW

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

- The Texas and Louisiana Gulf Coast
- The Rocky Mountains
- The Mid-Continent or Anadarko Basin
- The Eastern area of the United States

Operationally, we have regional offices located in three regions – the Gulf Coast region, the Western region, which is comprised of the Rocky Mountains and Mid-Continent areas, and the Eastern region.

In 2002, our natural gas and oil production reached its highest annual level in our history. We produced 91.1 Bcfe, or 249.7 Mmcfe per day this year. This is a 12% improvement over 2001 when we produced 81.1 Bcfe, or 222.3 Mmcfe per day. Of this 12% growth, 8% was associated with the full year impact of properties acquired from Cody Company in August 2001. The remaining 4% was a result of drilling during the past two years, primarily in south Louisiana. Commodity prices were much softer in 2002, however, and despite the increases in production, revenue and net income levels decreased in 2002 compared to 2001. Our 2002 realized natural gas price was $3.02 per Mcf, down 31% from 2001 due to a decline in natural gas prices. Our realized crude oil price was $23.79 per Bbl, down 4% from 2001 primarily due to the impact of crude oil collars which reduced our realized price by $1.81 per Bbl.

Net income of $16.1 million or $0.51 per share was under last year's record of $47.1 million or $1.56 per share. Lower commodity prices were the primary reason for this year's revenue decline. Prices have recovered somewhat during the fourth quarter and into early 2003. In order to reduce the risk of price declines in 2003, we have collar and swap arrangements in place on 51% of our anticipated natural gas production and 42% (31% relates to oil range swaps) of our anticipated oil production as of December 31, 2002.

In 2002, 93% of the wells that we drilled were successful. Drilling was successful on 67% of our 2002 exploration wells, as we tested new ideas and worked on building a foundation for the future. This was an improvement over an 87% overall success rate in 2001 and a 40% success rate on exploration wells. Our 2002 capital and exploration spending was $126.3 million, including $19.6 million for seismic data and lease acquisition. This spending will support our exploration and development drilling programs in 2003 and beyond. As we entered 2002, energy commodity prices softened from the unusually high level enjoyed in 2001. We concentrated our 2002 capital spending program on projects balancing acceptable risk with the strongest economics. As in the past, we will use 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 and Rocky Mountain areas. We believe these two core producing areas offer more value, through accretive reserve and production growth and higher rates of return on equity. This strategy remains in place for 2003. In 2003, we plan to spend $153.9 million and drill 180 gross wells.

Our proved reserves totaled approximately 1.2 Tcfe at December 31, 2002, of which 91% was natural gas. This reserve level rose just slightly above the prior year end in a year when production rose 12% while the level of total program spending was 76% below 2001. Highlighting the success of the 2002 program was Redfish Bay in the Gulf Coast and Double Eagle Field in Colorado.

The following table presents certain information as of December 31, 2002.

	Gulf Coast	West: Rocky Mountains	West: Mid-Continent	West: Total West	East	Total
Proved Reserves at Year End *(Bcfe)*						
Developed	200.0	184.4	171.4	355.8	343.2	899.0
Undeveloped	85.4	48.6	26.1	74.7	112.2	272.3
Total	**285.4**	**233.0**	**197.5**	**430.5**	**455.4**	**1,171.3**
Average Daily Production *(Mmcfe per day)*	127.0	42.7	30.3	73.0	49.7	249.7
Reserve Life Index *(in years)*[1]	6.2	15.0	17.8	16.2	25.1	12.9
Gross Wells	900	491	603	1,094	2,401	4,395
Net Wells[2]	549.0	221.1	422.3	643.4	2,215.6	3,408.0
Percent Wells Operated	79.3%	51.3%	78.6%	66.4%	96.6%	85.5%
Net Acreage						
Developed	100,861	85,332	182,340	267,672	741,652	1,110,185
Undeveloped	53,181	370,470	3,058	373,528	214,351	641,060
Total	**154,042**	**455,802**	**185,398**	**641,200**	**956,003**	**1,751,245**

(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 concentrated in south Louisiana and south Texas. A regional office in Houston manages operations. Principal producing intervals are in the Frio, Wilcox and Vicksburg formations in Texas and the Miocene and Frio age formations in Louisiana at depths ranging from 3,000 to 20,500 feet. Capital and exploration expenditures were $69.0 million for 2002 or 55% of our total 2002 capital and exploration expenditures, and $352.1 million for 2001. The cash and common stock portion of the August 2001 acquisition of Cody Company accounted for $231.2 million of this amount, which did not include a non-cash deferred tax gross-up of $78.0 million (See "*Limited Partnership*" on page 38 for discussion related to the Cody acquisition). Our drilling and acquisition program has increased average daily production in the region from 15.6 Mmcfe per day in 1994, when we acquired our first Gulf Coast properties from Washington Energy, to 127.0 Mmcfe per day in 2002. Of this production rate, 35.8 Mmcfe per day was associated with the Cody properties and the remaining primarily represents production growth from our drilling activity. For 2003, we have budgeted $88.1 million (57% of our total 2003 budget) for capital and exploration expenditures in the region. Our 2003 Gulf Coast drilling program will emphasize impact exploration opportunities both on and off shore augmented by development activity in our focus areas of south Texas and coastal Louisiana, including properties acquired in the Cody acquisition.

We had 900 wells (549.0 net) in the Gulf Coast region as of December 31, 2002, of which 714 wells are operated by us. Average net daily production in 2002 was 127.0 Mmcfe, up from 97.9 Mmcfe in 2001 due both to drilling success in south Louisiana and to the Cody acquisition. At December 31, 2002, we had 285.4 Bcfe of proved reserves (69% natural gas) in the Gulf Coast region, which represented 24% of our total proved reserves.

In 2002, we drilled 24 wells (12 net) in the Gulf Coast region, of which 16 wells (8 net) were development wells. The south Louisiana Etouffee prospect and our 2001 discoveries in the Augen field in south Louisiana and Red Fish Bay prospects in south Texas, together with the Cody acquisition, contributed to the significant growth in net proved reserves. In the Gulf Coast region, we plan to drill 43 wells in 2003.

At December 31, 2002, we had 154,042 net acres in the region, including 100,861 net developed, and we had identified 115 proved undeveloped drilling locations.

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

Currently, approximately 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. From time to time when we believe market conditions are favorable, we may implement financial hedges on a portion of our production in an attempt to reduce our exposure to price volatility. The Gulf Coast properties are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

We currently produce and market approximately 7,900 barrels per day of crude oil/condensate in the Gulf Coast region at market responsive prices.

Western Region

Our activities in the Western region are managed by a regional office in Denver. At December 31, 2002, we had 430.5 Bcfe of proved reserves (96% natural gas) in the Western region, constituting 37% of our total proved reserves.

Rocky Mountains

Our Rocky Mountains activities are concentrated in the Green River Basin of Wyoming and Paradox Basin in Colorado. Since our initial acquisition in the area in 1994 from Washington Energy, we have increased reserves from 171.6 Bcfe at December 31, 1994, to 233.0 Bcfe at December 31, 2002. Capital and exploration expenditures were $25.9 million for 2002, or 21% of our total 2002 capital and exploration expenditures, and $42.9 million for 2001. In addition to drilling activity, approximately $1.9 million was expended in 2002 for lease acquisition and seismic data to provide exploration and development opportunities in the future. For 2003, we have budgeted $20.0 million (13% of our total 2003 budget) for capital and exploration expenditures in the area. The 2003 drilling program consists of several new exploration plays complemented by development drilling.

We had 491 wells (221.1 net) in the Rocky Mountains area as of December 31, 2002, of which 252 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 2002 was 42.7 Mmcfe.

In 2002, we drilled 26 wells (10 net) in the Rocky Mountains, of which 25 wells (9 net) were development and extension wells. In 2003, we plan to drill 31 wells.

At December 31, 2002, we had 455,802 net acres in the area, including 85,332 net developed acres, and we had identified 75 proved undeveloped drilling locations.

Mid-Continent

Our Mid-Continent activities are concentrated in the Anadarko Basin in southwestern Kansas, Oklahoma and the panhandle of Texas. Capital and exploration expenditures were $8.2 million for 2002, or 6% of our total 2002 capital and exploration expenditures, and $11.5 million for 2001. For 2003, we have budgeted $11.5 million (7% of our total 2003 budget) for capital and exploration expenditures in the area.

As of December 31, 2002, we had 603 wells (422.3 net) in the Mid-Continent area, of which 474 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 2002 was 30.3 Mmcfe. At December 31, 2002, we had 197.5 Bcfe of proved reserves (97% natural gas) in the Mid-Continent area, 17% of our total proved reserves.

In 2002, we drilled 14 wells (12 net) in the Mid-Continent, all of which were development and extension wells. In 2003, we plan to drill 24 wells.

At December 31, 2002, we had 185,398 net acres in the area, including 182,340 net developed acres, and we had identified 58 proved undeveloped drilling locations.

Western Region Marketing

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. This marketing subsidiary sells the natural gas to power generators, natural gas processors, local distribution companies, industrial customers and marketing companies.

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

We currently also produce and market approximately 450 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, Pennsylvania, Ohio and Virginia. In this region, our assets include a large undeveloped acreage position, a high concentration of wells, natural gas gathering and pipeline systems, and storage capacity. We have achieved a drilling success rate of 89% in the region since 1991. Capital and exploration expenditures were $22.1 million for 2002, or 17% of our total 2002 capital spending, and $44.1 million for 2001. For 2003, we have budgeted $27.7 million (18% of our total 2003 budget) for capital and exploration expenditures in the region.

At December 31, 2002, we had 2,401 wells (2,215.6 net), of which 2,319 wells are operated by us. There are multiple producing intervals that include the Devonian Shale, Oriskany, Berea, Weir, and Big Lime formations at depths primarily ranging from 1,500 to 9,000 feet. Average net daily production in 2002 was 49.7 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, 2002, we had 455.4 Bcfe of proved reserves (substantially all natural gas) in the Eastern region, constituting 39% of our total proved reserves. This region is managed from our office in Charleston, West Virginia.

In 2002, we drilled 44 wells (39 net) in the Eastern region, of which 43 wells (38 net) were development wells. In 2003, we plan to drill 82 wells.

At December 31, 2002, we had 956,003 net acres in the region, including 741,652 net developed, and we had identified 316 proved undeveloped drilling locations.

Ancillary to our exploration, development and production operations, we operate a number of gas gathering and transmission pipeline systems, made up of approximately 2,500 miles of pipeline with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2002. The majority of our pipeline infrastructure in West Virginia is regulated by the Federal Energy Regulatory Commission (FERC). As such, the transportation rates and terms of service of our pipeline subsidiary, Cranberry Pipeline Corporation, are subject to the rules and regulations of the FERC. Our natural gas gathering and transmission pipeline systems enable us to connect new wells quickly and to transport natural gas from the wellhead directly to interstate pipelines, local distribution companies and industrial end users. Control of our gathering and transmission pipeline systems also enables us to purchase, transport and sell natural gas produced by third parties. In addition, we can engage in development drilling without relying upon third parties to transport our natural gas and incur only the incremental costs of pipeline and compressor additions to our system.

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

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

Eastern Region Marketing

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. This marketing subsidiary sells natural gas to industrial customers, local distribution companies and gas marketers both on and off our pipeline and gathering system.

Approximately 65% of our natural gas sales volume in the 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 5% of Eastern production is sold on fixed price contracts that typically renew annually. From time to time, we may also use financial hedges on a portion of our production to reduce the potential risk of falling prices when we believe market conditions are favorable.

RISK MANAGEMENT

From time to time, when we believe that market conditions are favorable, we use certain financial instruments called derivatives to manage price risks associated with our production and brokering activities. While there are many different types of derivatives available, in 2002 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 had certain costless collar arrangements on half of our natural gas production for the months of February through October 2001. These financial instruments resulted in a $0.50 per Mcf increase to our realized natural gas price. In 2002, we employed both price swaps and collars for 57% of our natural gas and 43% of our crude oil as part of our risk reduction strategy. These financial instruments resulted in a $0.01 per Mcf decline to our realized natural gas price and a $1.81 per Bbl decline to our realized crude oil price. 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, 2002.

	Natural Gas *(Mmcf)*			**Liquids**[1] *(Mbbl)*			**Total**[2] *(Mmcfe)*		
	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	Total
Gulf Coast	137,531	58,203	195,734	10,415	4,541	14,956	200,022	85,445	285,467
Rocky Mountains	175,532	45,522	221,054	1,481	511	1,992	184,415	48,588	233,003
Mid-Continent	165,808	25,619	191,427	934	74	1,008	171,413	26,064	197,477
East	340,541	112,203	452,744	437	—	437	343,166	112,203	455,369
Total	**819,412**	**241,547**	**1,060,959**	**13,267**	**5,126**	**18,393**	**899,016**	**272,300**	**1,171,316**

[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 2002.

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 often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. In general, the volume of production from oil and gas properties declines as reserves are depleted. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced.

Historical Reserves

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

	Natural Gas *(Mmcf)*	Oil & Liquids *(Mbbl)*	Total *(Mmcfe)*[1]
December 31, 1999	**929,602**	**8,189**	**978,741**
Revision of Prior Estimates	(14,796)	562	(11,423)
Extensions, Discoveries and Other Additions	103,600	2,032	115,792
Production	(60,934)	(988)	(66,872)
Purchases of Reserves in Place	5,118	120	5,838
Sales of Reserves in Place	(3,368)	(1)	(3,373)
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**
Proved Developed Reserves			
December 31, 1999	720,670	5,546	753,944
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**

[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,		
	2002	2001	2000
Net Wellhead Sales Volume			
Natural Gas *(Bcf)*			
Gulf Coast	**30.4**	25.6	14.1
West	**25.3**	26.2	29.0
East	**18.0**	17.4	17.8
Crude/Condensate/Ngl *(Mbbl)*			
Gulf Coast	**2,655**	1,694	669
West	**221**	267	289
East	**33**	35	32
Produced Natural Gas Sales Price *($/Mcf)* [1]			
Gulf Coast	**$ 3.34**	$ 4.44	$ 3.79
West	**2.39**	3.88	2.86
East	**3.38**	4.96	3.24
Weighted Average	**3.02**	4.36	3.19
Crude/Condensate Sales Price *($/Bbl)*[1]	**$ 23.79**	$ 24.91	$ 26.81
Production Costs *($/Mcfe)*[2]	**$ 0.70**	$ 0.72	$ 0.70

[1]*Represents the average sales prices (net of hedge activity) for all production volumes (including royalty volumes) sold by Cabot Oil & Gas during the periods shown net of related costs (principally purchased gas royalty, transportation and storage).*

[2]*Production costs include direct lifting costs (labor, repairs and maintenance, materials and supplies), and the costs of administration of production offices, insurance and property and severance taxes, but is exclusive of depreciation and depletion applicable to capitalized lease acquisition, exploration and development expenditures.*

Acreage

The following tables summarize our gross and net developed and undeveloped leasehold and mineral acreage at December 31, 2002. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

Leasehold Acreage

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
State						
Arkansas	1,981	426	—	—	1,981	426
Colorado	14,263	13,359	210,041	107,566	224,304	120,925
Kansas	29,067	27,745	—	—	29,067	27,745
Kentucky	2,266	901	—	—	2,266	901
Louisiana	51,281	41,428	30,152	20,547	81,433	61,975
Michigan	544	157	—	—	544	157
Montana	397	210	35,609	27,791	36,006	28,001
New York	2,956	1,117	400	151	3,356	1,268
New Mexico	160	36	—	—	160	36
North Dakota	—	—	870	96	870	96
Ohio	6,228	2,387	1,624	431	7,852	2,818
Oklahoma	162,942	113,304	2,784	2,528	165,726	115,832
Pennsylvania	131,975	81,852	19,741	17,650	151,716	99,502
Texas	149,273	85,852	80,697	32,762	229,970	118,614
Utah	1,740	529	169,425	101,387	171,165	101,916
Virginia	22,195	20,072	8,226	5,606	30,421	25,678
West Virginia	572,220	538,170	178,377	138,616	750,597	676,786
Wyoming	142,230	71,234	216,105	132,988	358,335	204,222
Total	**1,291,718**	**998,779**	**954,051**	**588,119**	**2,245,769**	**1,586,898**

Mineral Fee Acreage

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
State						
Colorado	—	—	2,899	567	2,899	567
Kansas	160	128	—	—	160	128
Louisiana	628	276	—	—	628	276
Montana	—	—	589	75	589	75
New York	—	—	4,281	1,070	4,281	1,070
Oklahoma	16,580	13,979	400	76	16,980	14,055
Pennsylvania	86	86	2,367	1,296	2,453	1,382
Texas	27	27	652	326	679	353
Virginia	17,817	17,817	100	34	17,917	17,851
West Virginia	97,455	79,093	50,458	49,497	147,913	128,590
Total	**132,753**	**111,406**	**61,746**	**52,941**	**194,499**	**164,347**
Aggregate Total	**1,424,471**	**1,110,185**	**1,015,797**	**641,060**	**2,440,268**	**1,751,245**

Total Net Acreage by Region of Operation

	Developed	Undeveloped	Total
Gulf Coast	100,861	53,181	154,042
West	267,672	373,528	641,200
East	741,652	214,351	956,003
Total	**1,110,185**	**641,060**	**1,751,245**

Well Summary

The following table presents our ownership at December 31, 2002, 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, Pennsylvania, Virginia and Ohio). This summary includes natural gas and oil wells in which we have a working interest or had a reversionary interest as in the case of certain Section 29 tight sands and Devonian shale wells repurchased by us effective December 31, 2002.

	Natural Gas		Oil		Total[1]	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	579	361.7	321	187.3	900	549.0
West	1,039	609.9	55	33.5	1,094	643.4
East	2,377	2,204.5	24	11.1	2,401	2,215.6
Total	**3,995**	**3,176.1**	**400**	**231.9**	**4,395**	**3,408.0**

[1] *Total does not include service wells of 99.0 (58.5 net).*

Drilling Activity

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

	Year Ended December 31,					
	2002		2001		2000	
	Gross	**Net**	Gross	Net	Gross	Net
Gulf Coast						
Development Wells						
Successful	**15**	**7.3**	18	7.0	14	6.3
Dry	**1**	**0.3**	1	0.6	3	1.7
Extension Wells						
Successful	**—**	**—**	1	0.1	—	—
Dry	**1**	**0.3**	—	—	—	—
Exploratory Wells						
Successful	**5**	**3.3**	8	4.6	4	2.2
Dry	**2**	**0.9**	7	2.4	2	1.0
Total	**24**	**12.1**	35	14.7	23	11.2
Wells Acquired[1]	**—**	**2.4**	600	334.0	1	0.6
Wells in Progress at End of Period	**5**	**2.5**	5	3.6	2	1.1

	Year Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
West						
Development Wells						
Successful	**38**	**19.8**	43	24.9	33	22.7
Dry	**1**	**0.8**	3	1.5	3	1.0
Extension Wells						
Successful	—	—	5	2.4	7	3.9
Dry	—	—	—	—	—	—
Exploratory Wells						
Successful	—	—	1	0.8	1	0.3
Dry	**1**	**0.7**	4	3.0	1	0.5
Total	**40**	**21.3**	56	32.6	45	28.4
Wells Acquired [(1)]	—	—	10	0.1	1	0.4
Wells in Progress at End of Period	**1**	**0.2**	—	—	4	2.7

	Year Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
East						
Development Wells						
Successful	**41**	**37.2**	102	93.0	47	41.5
Dry	**2**	**0.6**	5	4.0	5	4.2
Extension Wells						
Successful	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Exploratory Wells						
Successful	**1**	**1.0**	3	3.0	5	3.8
Dry	—	—	7	6.3	4	2.5
Total	**44**	**38.8**	117	106.3	61	52.0
Wells Acquired [(1)]	—	—	19	19.0	—	—
Wells in Progress at End of Period	—	—	—	—	3	3.0

[(1)]*Includes the acquisition of net interest in certain wells in which we already held an ownership interest. Does not include certain interest in Section 29 tight sands and Devonian shale wells repurchased by us effective December 31, 2002.*

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 2002, approximately 14% of our total sales were made to one customer. This customer operates certain properties in which we have interests in the Gulf Coast and purchases all of the production from these wells. This customer is currently reselling 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 and 2000 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 ratability of production. The effect of these regulations is to limit the amounts of oil and natural gas we can produce from our wells, and to limit the number of wells or the locations where we can drill. Because these statutes, rules and regulations undergo constant review and often are amended, expanded and reinterpreted, we are unable to predict the future cost or impact of regulatory compliance. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. We do not believe, however, we are affected materially differently by these regulations than others in the industry.

Natural Gas Marketing, Gathering and Transportation

Federal legislation and regulatory controls have historically affected the price of the natural gas 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.

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. Among other provisions, this act will require that pipeline operators implement a pipeline integrity management program that must at a minimum include an inspection of 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.

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

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

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

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

Clean Water Act. The Federal Water Pollution Control Act (FWPCA or Clean Water Act) and resulting regulations, which are implemented through a system of permits, also govern the discharge of certain contaminants into waters of the United States. Sanctions for failure to comply strictly with the Clean Water Act are generally resolved by payment of fines and correction of any identified deficiencies. However, regulatory agencies could require us to cease construction or operation of certain facilities that are the source of water discharges. We believe that we 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, 2002, Cabot Oil & Gas had 347 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. In January 2003, we released 10 employees and will record associated expenses of $0.6 million during the first quarter of 2003.

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, 2002, 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.

Environmental Liability

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

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

A group of potentially responsible parties, including us, formed a group, called the Casmalia Negotiating Committee ("CNC"). The CNC has had extensive settlement discussions with the EPA and has entered into a consent decree, which will require the CNC to pay approximately $27 million toward Site clean up in return for a release from liability. On January 30, 2002, we placed $1,283,283 in an escrow account, representing our volumetric share of the CNC/United States settlement. This cash settlement, once released from escrow and paid to the federal government after the consent decree is entered by the court, will resolve all federal claims against us for response costs and will release us from all response costs related to the Site, except for future claims against us for natural resource damage, unknown conditions, transshipment risks and claims by third parties. Most of the CNC, including us, have purchased insurance designed to protect us from these liabilities not covered by the consent decree.

The State of California, a third party, has asserted a claim against the CNC and other companies alleged to have waste at Casmalia for costs the State incurred and will incur at the site. The CNC has presented the claim to its insurer. The ultimate disposition of this claim is unknown. However, given the size of the State's claim, and the number of parties allegedly responsible, the Company's share of this claim is expected to be immaterial.

We have established a reserve we believe to be adequate to provide for this environmental liability and related legal costs.

Wyoming Royalty Litigation

In June 2000, we were sued by two overriding royalty owners in Wyoming state court for unspecified damages. The plaintiffs have requested class certification under the Wyoming Rules of Civil Procedure and allege that we have improperly deducted costs of production from royalty payments to the plaintiffs and other similarly situated persons. Additionally, the suit claims that we have failed to properly inform the plaintiffs and other similarly situated persons of the deductions taken from royalties. In January 2002, thirteen overriding royalty owners sued us 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.

Although we believe that a number of our defenses are supported by Wyoming case law, a recent letter decision handed down by a state district court in another case does not support certain of the defenses. The decision has not been reduced to a formal order and it is not known what effect, if any, the decision will have on the pending cases.

In our federal case, the judge recently 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 these cases. The federal judge refused, however, to certify one question on check stub reporting 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. The plaintiffs in the federal case currently claim $5.5 million in damages for the deductions and related issues and $12.9 million in damages for violation of the check stub reporting statute. 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 both cases. We have a reserve that we believe is adequate to provide for these potential liabilities based on our estimate of the probable outcome of these matters. Should circumstances change, the potential impact could 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 have failed to pay royalty based upon the wholesale market value of the gas produced, that we have taken improper deductions from the royalty and have 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 $1/8^{th}$ royalty share of the gas sales contract settlement that we reached with Columbia in the 1995 Columbia 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. No trial or dispositive motions dates have been set and limited factual discovery is ongoing.

The investigation into this claim continues and it is in the discovery phase. We are vigorously defending the case. We have a reserve that we believe is 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 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, Inc. we acquired certain leases and wells from Wynn-Crosby 1996, Ltd. in 1997 and 1998 and as Cabot Oil & Gas Corporation we 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 we 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. There is a trial date of May 19, 2003. However, the recent addition of the Company as defendant, as well as others, is expected to lead to a continuance of that trial date. We have not had the opportunity to conduct discovery in this matter. The Company estimates that production revenue from this field since its predecessor, Cody Energy, acquired title and since the Company acquired its lease is approximately $12 million. The carrying value of this property is approximately $35 million.

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 period from October 1, 2002 to December 31, 2002.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information about our executive officers as of February 15, 2003, 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	49	Chairman of the Board, Chief Executive Officer and President	2001
Michael B. Walen	54	Senior Vice President, Exploration and Production	1998
J. Scott Arnold	49	Vice President, Land and Associate General Counsel	1998
R. Scott Butler	48	Vice President, Regional Manager, Western Region	2001
Robert G. Drake	55	Vice President, Information Services and Operational Accounting	1998
Abraham D. Garza	56	Vice President, Human Resources	1998
Jeffrey W. Hutton	47	Vice President, Marketing	1995
Lisa A. Machesney	47	Vice President, Managing Counsel and Corporate Secretary	1995
A. F. (Tony) Pelletier	50	Vice President, Regional Manager, Gulf Coast Region	2001
Scott C. Schroeder	40	Vice President and Chief Financial Officer	1997
Henry C. Smyth	56	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 of the Board, Chief Executive Officer and President 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.

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

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

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
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**
2001	First Quarter	$ 32.00	$ 25.88	$ 0.04
	Second Quarter	34.20	24.22	0.04
	Third Quarter	26.33	16.70	0.04
	Fourth Quarter	24.99	18.35	0.04

As of January 31, 2003, there were 853 registered holders of the Common Stock. Shareholders include individuals, brokers, nominees, custodians, trustees, and institutions such as banks, insurance companies and pension funds. Many of these hold large blocks of stock on behalf of other individuals or firms.

ITEM 6. Selected Historical Financial Data

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

	Year Ended December 31,				
(In thousands, except per share amounts)	**2002**	2001	2000	1999	1998
Income Statement Data					
Operating Revenues	**$ 353,756**	$ 447,042	$ 368,651	$ 294,037	$ 251,340
Income from Operations	**49,088**	95,366	64,817	39,498	27,403
Net Income Available to Common Stockholders	**16,103**	47,084	29,221	5,117	1,902
Basic Earnings per Share Available to Common Stockholders [1]	**$ 0.51**	$ 1.56	$ 1.07	$ 0.21	$ 0.08
Dividends per Common Share	**$ 0.16**	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Balance Sheet Data					
Properties and Equipment, Net	**$ 954,737**	$ 981,338	$ 623,174	$ 590,301	$ 629,908
Total Assets	**1,054,871**	1,069,031	735,634	659,480	704,160
Long-Term Debt	**365,000**	393,000	253,000	277,000	327,000
Stockholders' Equity	**350,657**	346,552	242,505	186,496	182,668

[1] *See Earnings per Common Share under Note 15 of the Notes to the Consolidated Financial Statements.*

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 40.

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

OVERVIEW

Our financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas market has remained prevalent in the last few years. In early 2001, the NYMEX futures market reported unprecedented natural gas contract prices. We benefited from this market with our realized natural gas price reaching $5.66 per Mcf in December and $8.46 per Mcf in January 2001. When the NYMEX futures market was near its high on the last day of December 2000, we entered into a series of price collars that protected us from the subsequent price decline until their expiration in October 2001. (See the Commodity Price Swaps and Options discussion about hedging on page 45.) These price collar arrangements boosted 2001 revenue by $34.6 million, increasing the average realized natural gas price by $0.50 per Mcf. In 2002, natural gas prices rose throughout the year beginning with a $2.60 per Mcf price in January and ending with a December realized price of $4.17 per Mcf. This pattern is contrary to the pattern of prices declining throughout the year as seen in 2001.

The tables below illustrate how natural gas prices have fluctuated over the course of 2001 and 2002. "Index" represents the Henry Hub index price per Mmbtu. The "2001" and "2002" 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 - 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**

Natural Gas Prices by Month - 2001

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

Prices for crude oil have followed a similar path as the commodity market fell through 2001 and rose during 2002. The tables below contain the West Texas Intermediate index price (Index) and our realized per Bbl crude oil prices by month for 2001 and 2002.

(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**

(In $ per Bbl) **Crude Oil Prices by Month - 2001**

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

We reported earnings of $0.51 per share, or $16.1 million, for 2002. This is down from the $1.56 per share, or $47.1 million, reported in 2001. The weaker price environment coupled with the impact of our hedge arrangements were the driving factors in this decline. Prices, including the impact of the hedge arrangements, fell 31% for natural gas and 4% for oil. Partially offsetting this negative price impact, natural gas production was up 7% and crude oil sales volumes were up 50% from last year. Overall, on a Mcfe basis, our production grew more than 12% over 2001. An 8% production increase was a result of the full year impact of the acquisition of Cody Company, which was effective August 1, 2001, and the remaining 4% resulted from our drilling activities.

We drilled 108 gross wells with a success rate of 93% in 2002 compared to 208 gross wells and an 87% success rate in 2001. Total capital expenditures were $126.3 million in 2002 compared to $453.4 million for 2001, which included $181.3 million in cash and $49.9 million in common stock paid for Cody Company. Capital spent in drilling activity decreased $52.5 million from 2001 which remains our largest capital program to date. In previous years, our capital spending, excluding major acquisitions, used substantially all of our operating cash flow. In 2002, our capital and exploration expenditures were under this level, allowing us the reduce debt by $28.0 million. Our strategy in 2003 is anticipated to remain consistent with 2002. We believe our operating cash flow in 2003 will be sufficient to fund our capital and exploration budgeted spending of $154 million and again provide excess cash flow to reduce debt.

At the end of 2002, our debt-to-total capitalization ratio was 51.0%, an improvement from 53.1% at the end of 2001. This improvement was primarily the result of the decrease in debt levels and occurred despite a $13.8 million reduction in the Other Comprehensive Income portion of equity. During 2000, we improved our debt-to-total capitalization ratio from 61.1% at the end of 1999 to 52.6% at the close of 2000. This improvement was a result of several significant accomplishments. We sold 3.4 million shares of common stock in May 2000 for net proceeds of $71.5 million, of which $51.6 million was used to repurchase all of our preferred stock. The remaining proceeds, along with another $14.8 million from employee stock option exercises, were used to reduce debt and pay dividends. From year end 1999 to year end 2000, we reduced debt by $24 million.

We remain focused on our strategies to grow through the drill bit, 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 40.

FINANCIAL CONDITION

Capital Resources and Liquidity

Our capital resources consist primarily of cash flows from our oil and gas properties and asset-based borrowing supported by oil and gas reserves. Our level of earnings and cash flows depends on many factors, including the price of natural gas and oil, our ability to find and produce hydrocarbons and our ability to control and reduce costs. Demand for natural gas has historically been subject to seasonal influences characterized by peak demand and higher prices in the winter heating season. However, in the summer of 2000, our realized gas prices began to climb to unseasonably high levels and by January 2001, we realized the highest prices in the Company's history. Then in 2001, our realized natural gas price declined throughout the year to a low of $2.32 per Mcf in December. In 2002, commodity prices rose throughout the year, with December's realized natural gas price up 60% from the January price. A mild winter and the economic recession may have been contributing factors in the 2001 pricing volatility, while a colder winter and the threat of potential military activity in the Middle East may have contributed to rising prices in 2002.

The primary sources of cash during 2002 were funds generated from operations and, to a lesser extent, proceeds from the sale of non-strategic assets and the sale of stock. Funds were used primarily for exploration and development expenditures, reductions to the level of borrowing on the revolving credit facility, and dividend payments.

We had a net cash outflow of $3.1 million during 2002. The net cash inflow from operating activities of $165.1 million was sufficient to fund the $143.4 million of cash used for capital and exploration expenditures and $21.7 million of the reduction to debt. Cash proceeds from the sales of non-strategic assets and the sale of stock combined to provide an additional $8.1 million of cash flow.

(In millions)	**2002**	2001	2000
Cash Flows Provided by Operating Activities	**$ 165.1**	$ 250.4	$ 119.0

Cash flows provided by operating activities in 2002 were $85.3 million lower than in 2001. This decrease was the result of lower realized commodity prices combined with both an increase in accounts receivable and a decrease in accounts payable. Cash flows provided by operating activities in 2001 were $131.4 million higher than in 2000. This improvement was primarily a result of increased revenues from higher realized commodity prices and to a lesser extent to increased natural gas and oil production.

(In millions)	**2002**	2001	2000
Cash Flows Used by Investing Activities	**$ (138.6)**	$ (379.2)	$ (116.1)

Cash flows used by investing activities in 2002 were attributable to capital and exploration expenditures of $143.3 million, offset by the receipt of $4.7 million in proceeds received from the sale of non-strategic oil and gas properties.

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

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

(In millions)	**2002**	2001	2000
Cash Flows Provided (Used) by Financing Activities	**$ (29.6)**	$ 126.9	$ 3.0

Cash flows used by financing activities in 2002 included $28 million used to reduce the year-end debt balance to $365 million from $393 million in 2001 and cash used to pay cash dividends to stockholders.

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

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

We have a revolving credit facility with a group of banks, the revolving term of which runs to October 2006. The available credit line under this facility, currently $250 million, is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the banks' petroleum engineer) and other assets. Accordingly, oil and gas prices are an important part of this computation. Since the current price environment remains volatile, management can not predict how future price levels may change the banks' long-term price outlook. To reduce the impact of any redetermination, we strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. At year end, this excess capacity totaled $155 million, or 62% of the total available credit line. Management believes it has the ability to finance, if necessary, our capital requirements, including acquisitions. Oil and gas prices also affect the calculation of the financial ratios for debt covenant compliance. Please read Note 5 of the Notes to the Consolidated Financial Statements for a more detailed discussion of our revolving credit facility.

In the event that the available credit line is adjusted below the outstanding level of borrowings, we have a period of 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 2003 interest expense is expected to be approximately $23.6 million, including interest on the $170 million 7.33% weighted average fixed rate notes used to partially fund the acquisition of Cody Company.

Capitalization

Our capitalization information is as follows:

	As of December 31,		
(In millions)	**2002**	2001	2000
Long-Term Debt	**$ 365.0**	$ 393.0	$ 253.0
Current Portion of Long-Term Debt	**—**	—	16.0
Total Debt	**$ 365.0**	$ 393.0	$ 269.0
Stockholders' Equity			
Common Stock (net of Treasury Stock)	**$ 350.7**	$ 346.6	$ 242.5
Total Equity	**350.7**	346.6	$ 242.5
Total Capitalization	**$ 715.7**	$ 739.6	$ 511.5
Debt to Capitalization	**51.0%**	53.1%	52.6%

During 2002, dividends were paid on our common stock totaling $5.1 million. We have paid quarterly common stock dividends of $0.04 per share since becoming publicly traded in 1990. The amount of future dividends is determined by our Board of Directors and is dependent upon a number of factors, including future earnings, financial condition and capital requirements.

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

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, 2002.

(In millions)	**2002**	2001	2000
Capital Expenditures			
Drilling and Facilities	**$ 67.0**	$ 119.5	$ 80.0
Leasehold Acquisitions	**4.8**	12.9	10.9
Pipeline and Gathering	**4.1**	3.8	3.2
Other	**1.4**	1.9	2.6
	77.3	138.1	96.7
Proved Property Acquisitions	**8.8**	244.1[1]	6.0
Exploration Expenses	**40.2**	71.2	19.9
Total	**$ 126.3**	$ 453.4	$122.6

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

Total capital and exploration expenditures for 2002 decreased $327.1 million compared to 2001. The spending in 2001 included the $231.2 million Cody acquisition. The remaining $95.9 million of the decrease was due to smaller drilling and geological and geophysical programs for 2002. In 2002, we drilled 108 gross wells compared to 208 gross wells drilled in 2001 representing a 48% decline in drilling activity. Also, the 2001 drilling program included a $15.3 million increase in geological and geophysical expenses over 2000, including costs of obtaining seismic data that supports future drilling programs.

We plan to drill 180 gross wells in 2003 compared with 108 gross wells drilled in 2002. This 2003 drilling program includes $153.9 million in total capital and exploration expenditures, up from $126.3 million in 2002. Expected spending in 2003 includes $88.9 million for drilling and dry hole exposure, $10.8 million for lease acquisition and $12.9 million in geological and geophysical expenses. In addition to the drilling and exploration program, other 2003 capital expenditures are planned primarily for production equipment and for gathering and pipeline infrastructure maintenance and construction. We will continue to assess the commodity price environment and may increase or decrease the capital and exploration expenditures accordingly so as to not jeopardize our economic returns.

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, 2002.

(In thousands)	Total	Payments Due by Year 2003	2004 to 2005	2006 to 2007	2008 & Beyond
Long-Term Debt [1]	**$ 365,000**	$ —	$ 20,000	$ 135,000	$ 210,000
Operating Leases [2]	**27,153**	5,590	9,224	7,220	5,119
Total Contractual Cash Obligations	**$ 392,153**	$ 5,590	$ 29,224	$ 142,220	$ 215,119

[1] *$95 million of the amount shown as scheduled for payment in 2006 represents the December 31, 2002 balance outstanding on the revolving credit facility. Typically, we are able to replace this credit agreement with a new one as this comes due. See discussion in Note 5 of the Notes to the Consolidated Financial Statements.*

[2] *A discussion of operating leases can be found in Note 8 of the Notes to the Consolidated Financial Statements. We have no capital leases.*

Potential Impact of Our Critical Accounting Policies

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

Commodity Pricing and Risk Management Activities

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

We covered 16% of our production in 2000 with natural gas price collar arrangements and prices rose above the ceiling during some months. If we had not had these collars in place in 2000, our realized natural gas price would have been $0.17 per Mcf higher. In 2001, we covered 35% of our natural gas production with price collar arrangements and prices were below the floor for several months. The gains from the 2001 price collars improved our annual realized natural gas price by $0.50 per Mcf. During 2002, we hedged 57% of our natural gas production with a combination of price swaps and collars. The impact of these hedges reduced our 2002 realized natural gas price by $0.01 per Mcf. Also in 2002, 43% of our crude oil production was hedged with a series of price collars. The impact of these hedges reduced our realized crude oil price by $1.81 per Bbl in 2002.

Successful Efforts Method of Accounting

We use the successful efforts method of accounting for oil and gas producing activities. Under this method, acquisition costs for proved and unproved properties are capitalized when incurred. Exploration costs, including seismic purchases and processing, exploratory dry hole drilling costs and costs of carrying and retaining unproved properties are expensed as incurred. During 2002, we drilled nine exploratory wells and three of them were unsuccessful, adding $6.9 million to exploration expense. Additionally, we abandoned certain sections of exploration well bores that were not economical, in the amount of $3.9 million. This 67% success rate for exploratory wells is higher than our historical rate, and as we focus more on our exploration program, we are exposed to the risk of dry hole expense. Development costs, including the costs to drill and equip development wells, and successful exploratory drilling costs to locate proved reserves are capitalized.

We are also exposed to potential impairments if the book value of our assets exceeds their future expected cash flows. This may occur if a field discovers lower than anticipated reserves or if commodity prices fall below a level that significantly effects anticipated future cash flows on the field. We determine if an impairment has occurred through either adverse changes or as a result of the annual review of all fields. The impairment of unamortized capital costs is measured at a lease level and is reduced to fair value if it is determined that the sum of expected future net cash flows is less than the net book value. For the year-ended December 31, 2002, 2001 and 2000 we had impairment of long-lived asset expense of $2.7 million, $6.9 million, and $9.1 million, respectively.

Oil and Gas Reserves

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

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

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

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

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

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

Operating Risks and Insurance Coverage

Our business involves a variety of operating risks, including:

- blowouts, cratering and explosions;
- mechanical problems;
- uncontrolled flows of oil, natural gas or well fluids;
- fires;
- formations with abnormal pressures;
- pollution and other environmental risks; and
- natural disasters.

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

OTHER ISSUES AND CONTINGENCIES

Corporate Income Tax. We generate tax credits for the production of certain qualified fuels, including natural gas produced from tight sands formations and Devonian Shale. The credit for natural gas from a tight sand formation (tight gas sands) amounts to $0.52 per Mmbtu for natural gas sold prior to 2003 from qualified wells drilled in 1991 and 1992. A number of wells drilled in the 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 is estimated to be $1.10 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 will be 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 (see Note 5 of the Notes to the Consolidated Financial Statements) specify a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0. At December 31, 2002, the calculated ratio for 2002 was 7.9 to 1.0 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 and Note 5 of the Notes to the Consolidated Financial Statements.

Limited Partnership. As part of the Cody acquisition, we acquired a interest in certain oil and gas properties in the Kurten field, as general partner of a partnership and as an operator. Our current interest in Kurten is approximately 25%, including a one percent interest in the partnership. Under the partnership agreement, we have the right to a reversionary working interest that would bring our ultimate interest to 50% upon the limited partner reaching payout. Under the partnership agreement, the limited partner has the sole 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 has been 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 partners' decision and our decision to proceed with the liquidation, we performed an impairment review which resulted in an after-tax charge of approximately $55 million. This impairment charge will be reflected in the first quarter of 2003 as an operating expense but will not impact the Company's cash flows. In addition, we will record a downward reserve revision of approximately 16 Bcfe as a result of the loss of the reversionary interest.

CONCLUSION

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

2002: decreased 31% from 2001 to $3.02 per Mcf

2001: increased 37% over 2000 to $4.36 per Mcf

2000: increased 44% over 1999 to $3.19 per Mcf

1999: increased 3% over 1998 to $2.22 per Mcf

1998: decreased 15% from 1997 to $2.16 per Mcf

1997: increased 8% over 1996 to $2.53 per Mcf

The volatility of natural gas prices in recent years remains prevalent in 2003 with wide price swings in day-to-day trading on the NYMEX futures market. Given this continued price volatility, we can not predict with certainty what pricing levels will be in the future. Because future cash flows are subject to these variables, there is no assurance that our operations will provide cash sufficient to fully fund our planned capital expenditures. For these reasons, we periodically use derivative instruments to manage some of the price volatility.

While our 2003 plan now includes $153.9 million in capital and exploration spending, we will periodically assess industry conditions and adjust our 2003 spending plan to ensure the adequate funding of our capital requirements, including, if necessary, reductions in capital and exploration expenditures or common stock dividends. We plan on remaining disciplined in our capital program. We believe our capital resources, supplemented with external financing if necessary, are adequate to meet our capital requirements.

The preceding paragraphs contain forward-looking information. See Forward-Looking Information on page 40.

Recently Issued Accounting Pronouncements

In June 2001, the FASB approved for issuance 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 asset 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 will be reported as a cumulative effect of a change in accounting principle in January 2003. The impact on the financial statements of adopting SFAS 143 is disclosed in Note 12, "*Adoption of SFAS 143, Accounting for Asset Retirement Obligations*," to the financial statements.

In August 2001, the FASB also approved SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*." SFAS 144 replaces SFAS 121, "*Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*." The new accounting model for long-lived assets to be disposed of by sale applies to all long-lived assets, including discontinued operations, and replaces the provisions of APB Opinion No. 30, "*Reporting Results of Operations-Reporting the Effects of Disposal of a Segment of a Business*," for the disposal of segments of a business. SFAS 144 requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS 144 also broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of SFAS 144 are effective for financial statements issued for fiscal years beginning after December 15, 2001 and, were adopted by the Company in 2002. The adoption of this statement did not impact the Company's financial position, results of operations, or cash flows.

In April 2002, the FASB issued SFAS No. 145, "*Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections*." SFAS 145, which is effective for fiscal years beginning after May 15, 2002, provides guidance for income statement classification of gains and losses on extinguishment of debt and accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The adoption of this statement did not impact the Company's financial position, results of operations, or cash flows.

In June 2002, the FASB issued SFAS No. 146, "*Accounting for Costs Associated with Exit or Disposal Activities.*" SFAS 146 nullifies the guidance of the Emerging Issues Task Force (EITF) Issue No. 94-3, "*Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).*" SFAS 146 requires that a liability for a cost that is associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that fair value is the objective for the initial measurement of the liability. The provisions of SFAS 146 are required for exit or disposal activities that are initiated after December 31, 2002. The adoption of this statement did not impact the Company's financial position, results of operations, or cash flows.

In December 2002, the FASB issued SFAS No. 148, "*Accounting for Stock-Based Compensation – Transition and Disclosure*." SFAS 148 amends FASB Statement No. 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 Statement 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. The adoption of this statement did not impact the Company's financial position, results of operations, or cash flows. See Note 10, "Capital Stock," to the financial statements.

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 (VIE's). 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 VIE's. 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. This guidance applies immediately to VIE's created after January 31, 2003, and to VIE's in which an enterprise obtains an interest after that date. It applies in the first fiscal year or interim period beginning after June 15, 2003, to VIE's in which an enterprise holds a variable interest that it acquired before February 1, 2003. At this time, we have only one entity that could potentially be a VIE. We are evaluating this potential VIE, in which we have a one percent general partner interest and that holds an interest in the Kurten field, to determine if it is a VIE. However, pursuant to the Partnership agreement, the limited partner has elected to liquidate the Partnership. It is anticipated that this liquidation will be completed prior to the effective date of the Interpretation. See "*Limited Partnership*" on page 38 for discussion related to the Cody acquisition.

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

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

Selected Financial and Operating Data

(In millions except where specified)	**2002**	2001	2000
Operating Revenues	**$ 353.8**	$ 447.0	$ 368.7
Operating Expenses	**304.9**	351.7	303.8
Operating Income	**49.1**	95.4	64.8
Interest Expense	**25.2**	20.8	22.9
Net Income	**16.1**	47.1	29.2
Earnings Per Share – Basic	**$ 0.51**	$ 1.56	$ 1.07
Earnings Per Share – Diluted	**$ 0.50**	$ 1.53	$ 1.06
Natural Gas Production *(Bcf)*			
Gulf Coast	**30.4**	25.6	14.1
West	**25.3**	26.2	29.0
East	**18.0**	17.4	17.8
Total Company	**73.7**	69.2	60.9
Produced Natural Gas Sales Price *($/Mcf)*			
Gulf Coast	**$ 3.34**	$ 4.44	$ 3.79
West	**2.39**	3.88	2.86
East	**3.38**	4.96	3.24
Total Company	**$ 3.02**	$ 4.36	$ 3.19
Crude/Condensate			
Volume *(Mbbl)*	**2,869**	1,908	953
Price *($/Bbl)*	**$ 23.79**	$ 24.91	$ 26.81

2002 and 2001 Compared

Net Income and Revenues. During 2002, we reported net income of $16.1 million, or $0.51 per share. Operating income decreased $46.3 million, or 49%, and operating revenues decreased $93.3 million, or 21%, 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.

The average Gulf Coast natural gas production sales price declined $1.10 per Mcf, or 25%, to $3.34, decreasing operating revenues by approximately $33.4 million. In the Western region, the average natural gas production sales price decreased $1.49 per Mcf, or 38%, to $2.39, decreasing operating revenues by approximately $37.7 million. The average Eastern natural gas production sales price decreased $1.58 per Mcf, or 32%, to $3.38, decreasing operating revenues by approximately $28.4 million. The overall weighted average natural gas production sales price decreased $1.34 per Mcf, or 31%, to $3.02 per Mcf in 2002.

Natural gas production volume in the Gulf Coast region was up 4.8 Bcf, or 19%, to 30.4 Bcf primarily due to production from our discoveries in south Louisiana and production from the Cody Company properties acquired in August 2001. Natural gas production volume in the Western region was down 0.9 Bcf, or 3%, to 25.3 Bcf due primarily to a 29% decline in drilling activity, offset slightly by a 7% increase in the success rate. Natural gas production volume in the Eastern region was up 0.6 Bcf, or 3%, to 18.0 Bcf, as a result increased drilling activity in the region over the past year. Total natural gas production was up 4.5 Bcf, or 7%, in 2002.

Crude oil prices fell $1.12 per Bbl, or 4%, to $23.79, resulting in a decrease to operating revenues of approximately $3.2 million. The volume of crude oil sold in the year rose by 50% to 2,869 Mbbls, increasing operating revenues by $23.9 million. This production increase was a result of our 2000 and 2001 drilling success in south Louisiana (60% of the increase) and the acquisition of Cody Company (40% of the increase).

Brokered natural gas revenue decreased $32.0 million, or 35%, from the prior year. The sales price of brokered natural gas declined 35%, resulting in a decrease in revenue of $31.3 million. The volume of natural gas brokered this year declined by 1%, reducing revenues by $0.7 million. In prior years, the revenues and expenses related to brokering natural gas were reported net on the Consolidated Statement of Operations as Brokered Natural Gas Margin. Beginning in 2000, these amounts are reported gross as part of Operating Revenues and Operating Expenses. After including the related brokered natural gas costs, we realized a brokered gas margin of $5.7 million in 2002 compared to a brokered gas margin of $2.9 million in 2001.

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.

Costs and 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, or 40%, 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, or 44%, 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 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 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.

2001 and 2000 Compared

Net Income and Revenues. We reported net income in 2001 of $47.1 million, or $1.56 per share. During 2000, we reported net income of $29.2 million, or $1.07 per share. Operating income increased $30.5 million, or 47%, and operating revenues increased $78.4 million, or 21%, in 2001. The improvement in operating revenues was mainly a result of the $107.3 million rise in natural gas sales due to the increases in both natural gas prices and production, and the $22.0 million increase in crude oil sales revenue. In 2001 our natural gas revenue and our realized price were bolstered by the use of collar arrangements resulting in a $0.50 per Mcf increase to our realized natural gas price. See further discussion in Item 7A. These improvements were partially offset by a decline in brokered natural gas volume that reduced operating revenues by $50.4 million. Operating income was similarly impacted by these revenue changes.

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

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

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

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

Other operating revenues decreased $0.7 million to $7.1 million. In 2001, we received a $0.8 million settlement as a result of a lawsuit. In 2000, we realized miscellaneous net revenue of approximately $2.2 million primarily from the settlement of a natural gas sales contract.

Costs and Expenses. Total costs and expenses from operations increased $47.9million, or 16%, from 2000 due primarily to the following:

- Brokered natural gas cost decreased $47.9 million, or 35%, primarily due to the $73.0 million impact of the lower volume of brokered sales in 2001. This was partially offset by a $25.1 million increase due to higher natural gas costs compared to the prior year.
- Production and pipeline expense increased $5.5 million, or 15%, primarily as a result of costs associated with operating the Cody Company properties acquired in August 2001. Additionally, increased staffing and insurance costs were incurred to support the expanded 2001 drilling program. The 2000 expense includes $0.5 million related to the closure of the region office in Pittsburgh. On a units-of-production basis, our company-wide production and pipeline expense was $0.51 per Mcfe in 2001 versus $0.53 per Mcfe in 2000 as a result of the increased production discussed above.
- Exploration expense increased $51.3 million, or 258%, primarily as a result of the following:
  - A $15.3 million increase in geological and geophysical expenses over last year due to the acquisition of seismic data for future evaluation and increased drilling activity in all regions.
  - A $34.9 million increase in dry hole costs. Although the drilling success rate improved from 86% in 2000 to 87% in 2001, we drilled a total of 208 gross wells in 2001, a 61% increase over 2000. We recorded seven exploratory dry holes in the higher cost Gulf Coast region versus only two in 2000. We also recorded four exploratory dry holes in the Rocky Mountains area and seven in the Appalachian region for a total of 18, up from a Company total of seven in 2000.
  - A $0.8 million increase for salaries, wages and incentive compensation largely attributable to increased staffing in the Gulf Coast region to support the expanded drilling program.

- Depreciation, depletion, amortization and impairment expense increased $30.6 million, or 53%, over 2000. Natural gas equivalent production increased 21%, increasing DD&A expense by $12.3 million. The 27% increase in the per unit expense from $0.86 per Mcfe to $1.09 per Mcfe was a result of increased production in the higher cost Gulf Coast region (including the newly acquired Cody properties) and resulted in an $18.3 million increase to DD&A expense for 2001.
- Impairment of long-lived assets decreased $2.3 million from 2000. In 2001, 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. During 2000, we recorded a $9.1 million impairment on one field in the Gulf Coast due to casing collapse in two of the field's wells.
- General and administrative expenses increased $5.4 million, primarily as a result of increased staffing during the transition period following the Cody Company acquisition and other staffing increases that support our larger operations. Additional cost increases were realized in incentive compensation programs as well as technology updates and related software maintenance.
- Taxes other than income increased $5.3 million as a result of higher natural gas and oil revenues.

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

Income tax expense was up $11.0 million due to the comparable increase in earnings before income tax. Our effective tax rate decreased in 2001 reflecting a shift of activity between states.

ITEM 7A. Quantitative And Qualitative Disclosures About Market Risk

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

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and, to a lesser extent, oil. Declines in oil and natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil and gas prices also may reduce the amount of oil and gas that we can produce economically. Historically, oil and gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Oil and gas prices declined substantially in 1998 and early 1999, moved higher through 2000 and into 2001 before declining back to year-end 1998 levels in October 2001. Prices continued to decline for the remainder of 2001. From the end of 2001 through half of 2002 oil and gas prices were constant with an increase in prices during the fourth quarter. Because our reserves are predominantly natural gas, changes in natural gas prices may have a particularly significant impact on our financial results.

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

- The domestic and foreign supply of oil and natural gas.
- The level of consumer product demand.
- Weather conditions.
- Political conditions in oil producing regions, including the Middle East.
- The ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls.
- The price of foreign imports.
- Actions of governmental authorities.
- Domestic and foreign governmental regulations.
- The price, availability and acceptance of alternative fuels.
- Overall economic conditions.

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

Our hedging policy is designed to reduce the risk of price volatility for our production in the natural gas, natural gas liquids and crude oil markets. 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 against declines in oil and gas prices. These hedging arrangements may expose us to risk of financial loss and limit the benefit to us of increases in prices. Please read the discussion below related to commodity price swaps and Note 11 of the Notes to the Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

COMMODITY PRICE SWAPS AND OPTIONS

Hedges on Production - Swaps

From time to time, we enter into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of our production. These derivatives are not held for trading purposes. Under these price swaps, we receive a fixed price on a notional quantity of natural gas and crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures. Under our Revolving Credit Agreement, the aggregate level of commodity hedging must not exceed 80% of the anticipated future production during the period covered by the hedges. We did not have crude oil swap arrangements covering our production in 2000, 2001, or 2002. During 2002, we fixed the price at an average of $4.44 per Mcf on quantities totaling 7,870 Mmcf, representing 11% of our 2002 natural gas production. During 2001, we fixed the price at an average of $3.75 per Mcf on quantities totaling 918 Mmcf, representing approximately 1% of our 2001 natural gas production. During 2000, we fixed the price at an average of $4.54 per Mcf on quantities totaling 315 Mmcf, representing less than 1% of our 2000 natural gas production.

As of the years ended December 31, 2002, and 2001, we had no crude oil swap contracts that qualified as hedges outstanding. We had open natural gas price swap contracts on our production as follows:

	Natural Gas Price Swaps		
Contract Period	Volume in Mmcf	Weighted Average Contract Price	Unrealized Loss *(In $ millions)*
As of December 31, 2002			
Natural Gas Price Swaps on Production in:			
First Quarter of 2003	8,333	$ 4.44	
Second Quarter of 2003	7,107	4.24	
Third Quarter of 2003	7,186	4.24	
Fourth Quarter of 2003	7,186	4.24	
Full Year of 2003	**29,812**	**4.29**	**$ 15,062**
First Quarter of 2004	2,089	$ 4.42	
Second Quarter of 2004	2,089	4.42	
Third Quarter of 2004	2,112	4.42	
Fourth Quarter of 2004	2,112	4.42	
Full Year of 2004	**8,402**	**4.42**	**$ 1,753**
As of December 31, 2001			
None			

Natural gas price swaps increased revenue by $0.9 million in 2002 and reduced revenue by $0.8 million in 2001.

From time to time we enter into crude oil range swaps with counterparties. These derivatives do not qualify for hedge accounting under SFAS 133 and are recorded at fair value at the balance sheet date. We entered into two crude oil range swap arrangements as follows:

- A fixed price swap at $28.15 per barrel, unless the NYMEX West Texas Intermediate monthly average price falls below $21.00 per barrel. If the NYMEX West Texas Intermediate monthly average price falls below $21.00 per barrel for any month, the swap is cancelled for that month. This instrument covers 730 Mbbls of production over the period January 2003 through December 2003.

- A fixed price swap at $27.75 per barrel, unless the NYMEX West Texas Intermediate monthly average price falls below $21.00 per barrel. If the NYMEX West Texas Intermediate monthly average price falls below $21.00 per barrel for any month, the swap is cancelled for that month. This instrument covers 276 Mbbls of production over the period July 2003 through December 2003.

The crude oil range swaps at December 31, 2002 had a pre-tax unrealized loss in the amount of $0.7 million, which is reflected in crude oil operating revenue, and covered approximately 31% of our anticipated crude oil production during this period. We had no crude oil range swap contracts outstanding during 2001.

In January 2003, we entered into a natural gas swap arrangement to reduce the price risk on an additional portion of our 2003 production. The swap arrangement is in place for the months of February through December 2003 with a fixed price of $5.39 per Mcf. This hedge covers 1,597 Mmcf of our anticipated natural gas production for the year.

Hedges on Production - Options

In December 2001 and March 2002, we believed that the pricing environment provided a strategic opportunity to significantly reduce the price risk on a portion of our 2002 production through the use of a series of collars. Under the collar arrangements, if the index rises above the ceiling price, we pay the counterparty. If the applicable index falls below the floor, the counterparty pays us. The 2002 natural gas price hedges include several collar arrangements based on nine price indexes. The first series of natural gas price collars were in place for the months of January through April 2002 with a weighted average price floor of $2.68 per Mcf and a weighted average price ceiling of $3.53 per Mcf. These hedges covered 16,145 Mmcf, or 22% of our natural gas production for the year. The second series of natural gas price collars were in place for the months of May through August 2002 with a weighted average price floor of $2.54 per Mcf and a weighted average price ceiling of $3.17 per Mcf. These hedges covered 18,284 Mmcf, or 25% of our natural gas production for the year.

All indexes were within the collars during the month of January, all were below the floor for February through March, and most were above the ceiling in April through August, resulting in a cash expenditure of $1.4 million for the year. Overall, the natural gas collar and swap arrangements resulted in a reduction of $0.01 per Mcf to our average realized natural gas price for 2002.

During 2001, we used several costless collar arrangements to hedge a portion of our 2001 natural gas production. The 2001 natural gas price hedges include several costless collar arrangements based on eight price indexes at which we sell a portion of our production. These hedges were in place for the months of February through October 2001 and covered 24,404 Mmcf, or 35%, of our natural gas production for the year. All indexes were within the collars during February and April, some fell below the floor during the period of March, and all indexes were below the floor from June through October, resulting in a $34.6 million cash revenue for the year. These gains contributed $0.50 per Mcf to our average realized natural gas price for 2001.

Again in August 2002, we believed that the pricing environment provided a strategic opportunity to significantly reduce the price risk on a portion of our 2003 production through the use of natural gas price collar arrangements. As of the years ended December 31, 2002, and 2001, we had open natural gas price collar contracts on our production as follows:

	Natural Gas Price Collars		
Contract Period	Volume in Mmcf	Weighted Average Ceiling / Floor	Unrealized Loss *(In $ millions)*
As of December 31, 2002			
Natural Gas Collars on Production in:			
First Quarter of 2003	2,066	$5.03/$4.36	
Second Quarter of 2003	2,089	$5.03/$4.36	
Third Quarter of 2003	2,112	$5.03/$4.36	
Fourth Quarter of 2003	2,112	$5.03/$4.36	
Full Year of 2003	**8,379**	**$5.03/$4.36**	**$ 2,090**
As of December 31, 2001			
Natural Gas Costless Collars on Production in:			
First Quarter of 2002	12,082	$3.54/$2.68	
Second Quarter of 2002	4,027	$3.54/$2.68	
Full Year of 2002	**16,109**	**$3.54/$2.68**	**—**

The natural gas price collars open at December 31, 2002, noted above, included several collar arrangements based on two price indexes at which we sell a portion of our production. These hedges are in place for the full year of 2003 and cover approximately 11% of our anticipated natural gas production during this period. We also have crude oil collars open at December 31, 2002. These hedges are in place for the months of January through June 2003 with a weighted average price floor of $24.75 and a weighted average price ceiling of $28.86. These hedges cover approximately 11% of our anticipated crude oil production during this period. Crude oil collars reduced revenue by $5.2 million during 2002, but had no impact on 2001 results.

Subsequent to year end we entered into a series of natural gas costless collar and natural gas and crude oil price swap arrangements to significantly reduce the price risk on a portion of our 2003 and 2004 production. These arrangements are as follows:

- A natural gas costless collar in place for the months of February through December 2003 with a weighted average price floor of $4.71 per Mcf and a weighted average price ceiling of $5.98 per Mcf. This hedge covers 6,386 Mmcf of our anticipated natural gas production for the year.
- A natural gas costless collar in place for the full year of 2004 with a weighted average price floor of $4.33 per Mcf and a weighted average price ceiling of $5.42 per Mcf. This hedge covers 5,041 Mmcf of our anticipated natural gas production for the year.
- A natural gas costless collar in place for the full year of 2004 with a weighted average price floor of $4.16 per Mcf and a weighted average price ceiling of $5.25 per Mcf. This hedge covers 3,346 Mmcf of our anticipated natural gas production for the year.
- A natural gas costless collar in place for the months of March through December 2003 with a weighted average price floor of $3.91 per Mcf and a weighted average price ceiling of $5.08 per Mcf. This hedge covers 1,371 Mmcf of our anticipated natural gas production for the year.
- A natural gas price swap in place for the months of March through December 2003 with a fixed price of $4.46 per Mcf. This hedge covers 1,371 Mmcf of our anticipated natural gas production for the year.
- A fixed price swap at $30.00 per barrel, unless the NYMEX West Texas Intermediate monthly average price falls below $22.00 per barrel. If the NYMEX West Texas Intermediate monthly average price falls below $22.00 per barrel for any month, the swap is cancelled for that month. This instrument covers 92 Mbbls of production over the period July 2003 through December 2003.

Adoption of SFAS 133

We adopted SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*," 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.

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

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

As of December 31, 2001, we had a series of nine natural gas price collar arrangements outstanding. As of December 31, 2002 we had a series of 16 natural gas price swap arrangements, two natural gas price collar arrangements, two crude oil price collar arrangements, and two crude oil swap arrangements outstanding. In accordance with the latest guidance from the FASB's Derivative Implementation Group, we test the effectiveness of the combined intrinsic and time values and the effective portion of each will be recorded as a component of Other Comprehensive Income. Any ineffective portion will be recorded as a gain or loss in the current period. As of December 31, 2002, we had recorded $18.8 million of Other Comprehensive Income ($11.6 million net of deferred taxes), a $0.6 million Unrealized Hedge Loss in revenue, a $0.6 million Hedge Asset, and a $20.0 million Hedge Liability, exclusive of the crude oil range swaps. As of December 31, 2001, we had recorded $1.4 million of Other Comprehensive Income ($0.8 million net of deferred taxes), a $0.1 million Unrealized Hedge Gain in revenue and a $1.5 million Hedge Asset.

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, 2002		December 31, 2001	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Debt				
7.19% Notes	**$ 100,000**	**$ 113,591**	$ 100,000	$ 104,961
7.26% Notes	**75,000**	**86,231**	75,000	79,187
7.36% Notes	**75,000**	**86,461**	75,000	79,225
7.46% Notes	**20,000**	**23,322**	20,000	21,097
Credit Facility	**95,000**	**95,000**	123,000	123,000
	$ 365,000	**$ 402,605**	$ 393,000	$ 407,470

ITEM 8. Financial Statements And Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

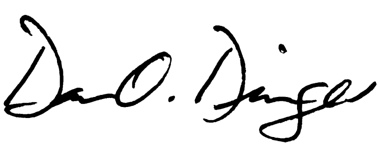
REPORT OF MANAGEMENT

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

Management maintains a system of internal accounting and managerial controls and engages internal audit representatives who monitor and test the operation of these controls. Although no system can ensure the elimination of all errors and irregularities, the system is designed to provide reasonable assurance that assets are safeguarded, transactions are executed in accordance with management's authorization, and accounting records are reliable for financial statement preparation.

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

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



Dan O. Dinges
Chairman of the Board, Chief Executive Officer and President

February 21, 2003

REPORT OF INDEPENDENT ACCOUNTANTS

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Cabot Oil & Gas Corporation and its subsidiaries at December 31, 2002 and 2001, 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, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 11 to the Notes to the Consolidated Financial Statements, the Company changed its method of accounting for its derivative instruments and hedging activities in connection with its adoption of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, on January 1, 2001.

PricewaterhouseCoopers LLP

Houston, Texas
February 17, 2003

CONSOLIDATED STATEMENT OF OPERATIONS

(In thousands, except per share amounts)

	Year Ended December 31,		
	2002	2001	2000
OPERATING REVENUES			
Natural Gas Production	**$ 221,101**	$ 301,671	$ 194,185
Brokered Natural Gas	**58,729**	90,710	141,085
Crude Oil and Condensate	**67,548**	47,544	25,544
Other (Note 13)	**6,378**	7,117	7,837
	353,756	447,042	368,651
OPERATING EXPENSES			
Brokered Natural Gas Cost	**53,007**	87,785	135,700
Direct Operations – Field and Pipeline	**50,047**	41,217	35,727
Exploration	**40,167**	71,165	19,858
Depreciation, Depletion and Amortization	**96,512**	80,619	53,441
Impairment of Unproved Properties	**9,348**	7,803	4,368
Impairment of Long-Lived Assets	**2,720**	6,852	9,143
General and Administrative	**28,377**	25,650	20,421
Bad Debt Expense (Note 3)	**—**	2,270	2,096
Taxes Other Than Income	**24,734**	28,341	23,041
	304,912	351,702	303,795
Gain (Loss) on Sale of Assets	**244**	26	(39)
INCOME FROM OPERATIONS	**49,088**	95,366	64,817
Interest Expense and Other	**25,311**	20,817	22,878
Income Before Income Tax Expense	**23,777**	74,549	41,939
Income Tax Expense	**7,674**	27,465	16,467
NET INCOME	**16,103**	47,084	25,472
Preferred Stock Dividend (Note 10)	**—**	—	(3,749)
Net Income Available to Common Stockholders	**$ 16,103**	$ 47,084	$ 29,221
Basic Earnings per Share Available to Common Stockholders	**$ 0.51**	$ 1.56	$ 1.07
Diluted Earnings per Share Available to Common Stockholders	**$ 0.50**	$ 1.53	$ 1.06
Average Common Shares Outstanding	**31,737**	30,276	27,384

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

CONSOLIDATED BALANCE SHEET

(In thousands, except share amounts)

	December 31, 2002	2000
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	**$ 2,561**	$ 5,706
Accounts Receivable	**70,028**	50,711
Inventories	**15,252**	17,560
Other	**5,280**	11,010
Total Current Assets	**93,121**	84,987
PROPERTIES AND EQUIPMENT (Successful Efforts Method)	**954,737**	981,338
OTHER ASSETS	**7,013**	2,706
	$ 1,054,871	$ 1,069,031
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	**$ 73,578**	$ 79,575
Accrued Liabilities	**49,446**	30,665
Total Current Liabilities	**123,024**	110,240
LONG-TERM DEBT	**365,000**	393,000
DEFERRED INCOME TAXES	**200,207**	200,859
OTHER LIABILITIES	**15,983**	18,380
COMMITMENTS AND CONTINGENCIES (Note 8)		
STOCKHOLDERS' EQUITY		
Preferred Stock		
Authorized – 5,000,000 Shares of $0.10 Par Value		
– 6% Convertible Redeemable Preferred; $50 Stated Value;		
No Shares Outstanding in 2002 and 2001 (Note 10)	**—**	—
Common Stock		
Authorized – 80,000,000 Shares of $0.10 Par Value		
Issued and Outstanding – 32,133,118 Shares in 2002 and 31,905,097 Shares in 2001	**3,213**	3,191
Additional Paid-in Capital	**353,093**	346,260
Retained Earnings	**11,674**	650
Accumulated Comprehensive (Loss) Income	**(12,939)**	835
Less Treasury Stock, at Cost		
302,600 Shares in 2002 and 2001	**(4,384)**	(4,384)
Total Stockholders' Equity	**350,657**	346,552
	$ 1,054,871	$ 1,069,031

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

CONSOLIDATED STATEMENT OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 16,103**	$ 47,084	$ 25,472
Adjustments to Reconcile Net Income			
to Cash Provided by Operations			
Depletion, Depreciation and Amortization	**96,512**	80,619	53,441
Impairment of Unproved Properties	**9,348**	7,803	4,368
Impairment of Long-Lived Assets	**2,720**	6,852	9,143
Deferred Income Tax Expense	**7,882**	14,157	13,162
(Gain) Loss on Sale of Assets	**(244)**	(26)	39
Exploration Expense	**40,167**	71,165	19,858
Change in Derivative Fair Value	**2,301**	(142)	—
Other	**3,963**	2,995	1,141
Changes in Assets and Liabilities			
Accounts Receivable	**(19,317)**	34,966	(35,286)
Inventories	**2,308**	(6,523)	(108)
Other Current Assets	**3,976**	(3,524)	(2,357)
Other Assets	**(4,307)**	(515)	348
Accounts Payable and Accrued Liabilities	**8,301**	(7,859)	26,976
Other Liabilities	**(4,572)**	3,383	2,813
Net Cash Provided by Operations	**165,141**	250,435	119,010
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital Expenditures	**(103,189)**	(127,129)	(99,359)
Acquisition of Cody Company [(1)]	**—**	(187,785)	—
Proceeds from Sale of Assets	**4,688**	6,829	3,150
Exploration Expense	**(40,167)**	(71,165)	(19,858)
Net Cash Used by Investing	**(138,668)**	(379,250)	(116,067)
CASH FLOWS FROM FINANCING ACTIVITIES			
Increase in Debt	**180,000**	435,000	135,000
Decrease in Debt	**(208,000)**	(311,000)	(159,000)
Sale of Common Stock	**3,461**	7,749	85,104
Common Dividends Paid	**(5,079)**	(4,802)	(4,350)
Preferred Dividends Paid	**—**	—	(2,202)
Retirement of Preferred Stock	**—**	—	(51,600)
Net Cash Provided (Used) by Financing	**(29,618)**	126,947	2,952
Net Increase (Decrease) in Cash and Cash Equivalents	**(3,145)**	(1,868)	5,895
Cash and Cash Equivalents, Beginning of Year	**5,706**	7,574	1,679
Cash and Cash Equivalents, End of Year	**$ 2,561**	$ 5,706	$ 7,574

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

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

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(In thousands)

	Common Shares	Stock Par	Preferred Stock	Treasury Stock	Paid-In Capital	Accumulated Comprehensive Income/(Loss)	Retained Earnings (Deficit)	Total
Balance at December 31, 1999	25,074	$ 2,507	$ 113	$ (4,384)	$ 254,763	$ —	$ (66,503)	$ 186,496
Net Income							25,472	25,472
Exercise of Stock Options	766	77			14,764			14,841
Preferred Stock Dividends							3,749	3,749
Common Stock Dividends at $0.16 per Share							(4,350)	(4,350)
Stock Grant Vesting	254	25			1,412			1,437
Issuance of Common Stock	3,400	340			71,219			71,559
Retirement of Preferred Stock			(113)		(56,586)			(56,699)
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	228	22			3,845			3,867
Common Stock Dividends at $0.16 per Share							(5,079)	(5,079)
Other Comprehensive Loss						(13,774)		(13,774)
Stock Grant Vesting					2,988			2,988
Balance at December 31, 2002	**32,133**	**$ 3,213**	**$ —**	**$ (4,384)**	**$ 353,093**	**$ (12,939)**	**$ 11,674**	**$ 350,657**

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(In thousands)

	Year Ended December 31,		
	2002	2001	2000
Net Income Available to Common Stockholders	**$ 16,103**	$ 47,084	$ 29,221
Other Comprehensive (Loss) Income			
Cumulative Effect of Change in Accounting Principle on January 1, 2001	**—**	(4,269)	—
Reclassification Adjustments for Settled Contracts	**(6,423)**	33,762	—
Changes in Fair Value of Outstanding Hedge Positions	**(13,708)**	(28,131)	—
Adjustment to Recognize Minimum Pension Liability	**(2,177)**	—	—
Deferred Income Tax	**8,534**	(527)	—
Total Other Comprehensive (Loss) Income	**(13,774)**	835	—
Comprehensive Income	**$ 2,329**	$ 47,919	$ 29,221

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 within the continental United States.

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

Recently Issued Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board (FASB) approved for issuance Statement of Financial Accounting Standard (SFAS) No. 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 asset 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 will be reported as a cumulative effect of a change in accounting principle in January 2003. The impact on the consolidated financial statements of adopting SFAS 143 is disclosed in Note 12, "*Adoption of SFAS 143, Accounting for Asset Retirement Obligations*."

In August 2001, the FASB approved SFAS 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*." SFAS 144 replaces SFAS 121, "*Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of.*" The new accounting model for long-lived assets to be disposed of by sale applies to all long-lived assets, including discontinued operations, and replaces the provisions of APB Opinion No. 30, "*Reporting Results of Operations-Reporting the Effects of Disposal of a Segment of a Business*," for the disposal of segments of a business. SFAS 144 requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS 144 also broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of SFAS 144 are effective for financial statements issued for fiscal years beginning after December 15, 2001 and therefore were adopted by the Company in 2002. The adoption of this statement did not impact the Company's financial position, results of operations, or cash flows.

In April 2002, the FASB issued SFAS No. 145, "*Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections*." SFAS 145, which is effective for fiscal years beginning after May 15, 2002, provides guidance for income statement classification of gains and losses on extinguishment of debt and accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The adoption of this statement did not impact the Company's financial position, results of operations, or cash flows.

In June 2002, the FASB issued SFAS No. 146, "*Accounting for Costs Associated with Exit or Disposal Activities.*" SFAS 146 nullifies the guidance of the Emerging Issues Task Force (EITF) Issue No. 94-3, "*Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).*" SFAS 146 requires that a liability for a cost that is associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that fair value is the objective for the initial measurement of the liability. The provisions of SFAS 146 are required for exit or disposal activities that are initiated after December 31, 2002. The adoption of this statement did not impact the Company's financial position, results of operations, or cash flows.

In December 2002, the FASB issued SFAS No. 148, "*Accounting for Stock-Based Compensation – Transition and Disclosure.*" SFAS 148 amends FASB Statement No. 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 Statement 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. The adoption of this statement did not impact the Company's financial position, results of operations, or cash flows. See Note 10, "*Capital Stock*."

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 (VIE's). 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 VIE's. 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. This guidance applies immediately to VIE's created after January 31, 2003, and to VIE's in which an enterprise obtains an interest after that date. It applies in the first fiscal year or interim period beginning after June 15, 2003, to VIE's in which an enterprise holds a variable interest that it acquired before February 1, 2003. At this time, the Company has only one entity that could potentially be a VIE. The Company is evaluating this potential VIE, in which it has a one percent general partnership interest (Partnership) and that holds an interest in the Kurten field, to determine if it is a VIE. However, pursuant to the Partnership agreement, the limited partner has elected to liquidate the Partnership. It is anticipated that this liquidation will be completed prior to the effective date of the Interpretation. See "*Limited Partnership*" on page 38 for discussion related to the Cody acquisition.

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 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. During 2000, two wells in the Beaurline field in south Texas experienced casing collapses.

This situation resulted in an impairment to this field of $9.1 million, recorded in the second quarter financial results. These impairments were measured based on discounted cash flows utilizing a discount rate appropriate for risks associated with the related properties.

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

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 Company believed that this accrual method adequately provided for its estimated future plug and abandonment costs of certain properties over the reserve life of the wells. 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.

Brokered Natural Gas Margin

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

The Company realizes brokered margin as a result of buying and selling natural gas in back-to-back transactions. The Company realized $5.7 million, $2.9 million, and $5.4 million of brokered natural gas margin in 2002, 2001, and 2000, respectively.

Income Taxes

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

Natural Gas Measurement

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

Accounts Payable

This account includes credit balances from outstanding checks in zero balance cash accounts. These credit balances included in accounts payable were $1.0 million at December 31, 2002, and $9.7 million at December 31, 2001.

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

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. The impact on the financial statements of using this method is disclosed in Note 10, "*Capital Stock*," to the financial statements.

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, 2002, and 2001, the cash and cash equivalents are primarily concentrated in one and two financial institutions, respectively. 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:

(In thousands)	December 31, 2002	2001
Proved Oil and Gas Properties	**$ 1,459,240**	$ 1,400,341
Unproved Oil and Gas Properties	**76,959**	70,709
Gathering and Pipeline Systems	**137,137**	131,768
Land, Building and Improvements	**4,884**	4,674
Other	**29,457**	27,513
	1,707,677	1,635,005
Accumulated Depreciation, Depletion, Amortization and Impairments	**(752,940)**	(653,667)
	$ 954,737	$ 981,338

As a component of accumulated depreciation, depletion and amortization, total future plug and abandonment costs were $17.1 million at December 31, 2002 and $14.4 million at December 31, 2001. See further discussion in Note 1.

3. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

	December 31,	
(In thousands)	**2002**	2001
Accounts Receivable		
Trade Accounts	**$ 65,796**	$ 39,570
Joint Interest Accounts	**6,601**	12,889
Current Income Tax Receivable	**2,479**	2,662
Other Accounts	**619**	986
	75,495	56,107
Allowance for Doubtful Accounts [1]	**(5,467)**	(5,396)
	$ 70,028	$ 50,711
Other Current Assets		
Derivative Instrument Asset – SFAS 133	**$ 634**	$ 2,387
Drilling Advances	**558**	2,111
Prepaid Balances	**2,131**	2,114
Restricted Cash and Other Accounts [2]	**1,957**	4,398
	$ 5,280	$ 11,010
Accounts Payable		
Trade Accounts	**$ 13,317**	$ 19,914
Natural Gas Purchases	**6,058**	4,559
Wellhead Gas Imbalances	**2,817**	2,353
Royalty and Other Owners	**20,254**	11,041
Capital Costs	**13,900**	30,923
Taxes Other than Income	**3,076**	2,686
Drilling Advances	**7,254**	2,627
Other Accounts	**6,902**	5,472
	$ 73,578	$ 79,575
Accrued Liabilities		
Employee Benefits	**$ 8,751**	$ 7,151
Taxes Other than Income	**9,887**	13,623
Interest Payable	**7,076**	6,996
Derivative Instrument Payable – FAS 133	**20,680**	—
Other Accrued	**3,052**	2,895
	$ 49,446	$ 30,665
Other Liabilities		
Postretirement Benefits Other than Pension	**$ 1,843**	$ 1,689
Accrued Pension Cost	**8,486**	7,280
Taxes Other than Income and Other	**5,654**	9,411
	$ 15,983	$ 18,380

(1) *Includes a $2.3 million addition in 2001 in connection with the Enron Corp. bankruptcy.*
(2) *Primarily represents cash in escrow for assumed Cody Company liabilities*

4. Inventories

Inventories are comprised of the following:

(In thousands)	December 31, 2002	2001
Natural Gas and Oil in Storage	$ 11,519	$ 12,622
Tubular Goods and Well Equipment	3,334	4,059
Pipeline Exchange Balances	399	879
	$ 15,252	$ 17,560

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, 2002, 2001, and 2000 were 3.4%, 7.6%, and 7.8%, 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, 2002 and 2001.

6. Employee Benefit Plans

Pension Plan

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

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

Net periodic pension cost of the Company for the years ended December 31, 2002, 2001 and 2000 are comprised of the following:

(In thousands)	**2002**	2001	2000
Qualified			
Current Year Service Cost	**$ 1,056**	$ 914	$ 832
Interest Accrued on Pension Obligation	**1,362**	1,198	1,070
Expected Return on Plan Assets	**(991)**	(1,064)	(1,123)
Net Amortization and Deferral	**88**	88	88
Recognized Loss (Gain)	**21**	(28)	(282)
Net Periodic Pension Cost	**$ 1,536**	$ 1,108	$ 585
Non-Qualified			
Current Year Service Cost	**$ 78**	$ 88	$ 60
Interest Accrued on Pension Obligation	**29**	72	42
Net Amortization	**77**	77	77
Loss Recognized from Settlement	**963**	—	—
Recognized (Gain) Loss	**7**	21	(5)
Net Periodic Pension Cost	**$ 1,154**	$ 258	$ 174

The following table illustrates the funded status of the Company's pension plans at December 31, 2002, and 2001, respectively:

	2002		2001	
(In thousands)	**Qualified**	**Non-Qualified**	Qualified	Non-Qualified
Actuarial Present Value of:				
Accumulated Benefit Obligation	**$ 18,136**	**$ 338**	$ 14,279	$ 816
Projected Benefit Obligation	**$ 23,530**	**$2,511**	$ 18,996	$ 898
Plan Assets at Fair Value	**10,279**	**—**	9,909	—
Projected Benefit Obligation in Excess of Plan Assets	**13,251**	**2,511**	9,087	898
Unrecognized Net Loss	**(7,283)**	**(2,462)**	(2,153)	(260)
Unrecognized Prior Service Cost	**(424)**	**(475)**	(511)	(553)
Adjustment to Recognize Minimum Liability	**2,313**	**764**	—	731
Accrued Pension Cost	**$ 7,857**	**$ 338**	$ 6,423	$ 816

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

(In thousands)	**2002**	2001	2000
Beginning of Year	**$ 19,894**	$ 17,151	$ 14,546
Service Cost	**1,134**	1,002	892
Interest Cost	**1,391**	1,270	1,112
Actuarial Loss	**5,860**	1,166	1,328
Benefits Paid	**(2,237)**	(695)	(727)
End of Year	**$ 26,042**	$ 19,894	$ 17,151

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

(In thousands)	**2002**	2001	2000
Beginning of Year	**$ 9,908**	$ 11,801	$ 12,092
Actual Return on Plan Assets	**(1,280)**	(1,527)	(440)
Employer Contribution	**4,080**	584	1,172
Benefits Paid	**(2,237)**	(695)	(727)
Expenses Paid	**(192)**	(254)	(296)
End of Year	**$ 10,279**	$ 9,909	$ 11,801

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

(In thousands)	**2002**	2001	2000
Funded Status	**$15,762**	$ 9,985	$ 5,350
Unrecognized Gain (Loss)	**(9,745)**	(2,413)	1,605
Unrecognized Prior Service Cost	**(899)**	(1,064)	(1,229)
Net Amount Recognized	**$ 5,118**	$ 6,508	$ 5,726
Accrued Benefit Liability – Qualified Plan	**$ 7,857**	$ 6,423	$ 5,729
Accrued Benefit Liability – Non-Qualified Plan	**338**	816	753
Intangible Asset	**(3,077)**	(731)	(756)
Net Amount Recognized	**$ 5,118**	$ 6,508	$ 5,726

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

	2002	2001	2000
Discount Rate[1]	**6.50%**	7.25%	7.50%
Rate of Increase in Compensation Levels	**4.00%**	4.00%	4.00%
Long-Term Rate of Return on Plan Assets	**9.00%**	9.00%	9.00%

(1) Represents the rate used to determine the benefit obligation. A 7.25% discount rate was used to compute pension costs in 2002, a rate of 7.50% in 2001, and a rate of 7.75% was used in 2000.

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 $1.3 million, $1.0 million, and $0.7 million in 2002, 2001, and 2000, respectively. The plan contribution rose in 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, 2002, the balance in the Deferred Compensation Plan's rabbi trust was $2.8 million.

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

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

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

Postretirement Benefits Other than Pensions

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits for retired employees, including their spouses, eligible dependents and surviving spouses (retirees). These benefits are commonly called postretirement benefits. Most employees become eligible for these benefits if they meet certain age and service requirements at retirement. The Company was providing postretirement benefits to 246 retirees at the end of 2002 and 240 retirees at the end of 2001.

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:

(In thousands)	**2002**	2001	2000
Service Cost of Benefits Earned During the Year	**$ 215**	$ 175	$ 187
Interest Cost on the Accumulated Postretirement Benefit Obligation	**381**	388	534
Amortization Benefit of the Unrecognized Gain	**(267)**	(291)	(132)
Amortization Benefit of the Unrecognized Transition Obligation	**662**	662	662
Total Postretirement Benefit Cost	**$ 991**	$ 934	$ 1,251

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

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

The funded status of the Company's postretirement benefit obligation at December 31, 2002, and 2001 is comprised of the following:

(In thousands)	**2002**	2001
Plan Assets at Fair Value	**$ —**	$ —
Accumulated Postretirement Benefits Other Than Pensions	**6,185**	5,507
Unrecognized Cumulative Net Gain	**2,113**	3,292
Unrecognized Transition Obligation	**(5,955)**	(6,617)
Accrued Postretirement Benefit Liability	**$ 2,343**	$ 2,182

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

(In thousands)	**2002**	2001	2000
Beginning of Year	**$ 5,507**	$ 5,429	$ 7,243
Service Cost	**215**	175	187
Interest Cost	**381**	388	534
Amendments	**—**	—	—
Actuarial Loss (Gain)	**912**	265	(1,923)
Benefits Paid	**(830)**	(750)	(612)
End of Year	**$ 6,185**	$ 5,507	$ 5,429

7. Income Taxes

Income tax expense is summarized as follows:

(In thousands)	Year Ended December 31, 2002	2001	2000
Current			
Federal	$ (1,158)[1]	$ 10,984[1]	$ 3,089
State	869	496	216
Total	(289)	11,480	3,305
Deferred			
Federal	7,931	13,723	11,804
State	32	2,262	1,358
Total	7,963	15,985	13,162
Total Income Tax Expense	$ 7,674	$ 27,465	$ 16,467

[1] *Federal Income Taxes Payable is zero at December 31, 2002 and 2001 primarily due to tax payments made during the current year and prior year 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, 2002	2001	2000
Statutory Federal Income Tax Rate	35%	35%	35%
Computed "Expected" Federal Income Tax	$ 8,322	$ 26,092	$14,679
State Income Tax, Net of Federal Income Tax	737	2,758	1,552
Other, Net	(1,385)[1]	(1,385[2]	236
Total Income Tax Expense	$ 7,674	$ 27,465	$16,467

[1] *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 2001 estimate-to-actual differences and non-provision additions.*

[2] *Other, Net includes credit adjustments totaling $1.7 million to deferred taxes as a result of a reduction to the state effective tax rate.*

The tax effects of temporary differences that resulted in significant portions of the deferred tax liabilities and deferred tax assets as of December 31, 2002, and 2001 were as follows:

(In thousands)	2002	2001
Deferred Tax Liabilities		
Property, Plant and Equipment	$ 229,583	$ 224,031
Deferred Tax Assets		
Alternative Minimum Tax Credit Carryforwards	12,083	4,943
Net Operating Loss Carryforwards	746	1,715
Note Receivable on Section 29 Monetization[1]	—	4,928
Items Accrued for Financial Reporting Purposes	8,540	11,059
Other Comprehensive Income	8,007	527
	29,376	23,172
Net Deferred Tax Liabilities	$ 200,207	$ 200,859

[1] *In December 2002, the Company repurchased assets associated with Section 29 credits sold in 1995 and 1996. Accordingly, the remaining deferred gain from the installment sale and deferred loss associated with unrealized receivables was recognized in 2002.*

As of December 31, 2002, the Company had a net operating loss carryforward of $11.6 million for state income tax reporting purposes, the majority of which will expire between 2012 and 2018 and none available for regular federal income tax purposes. The Company has alternative minimum tax credit carryforwards of $12.1 million which does not expire and is available to offset regular income taxes in future years to the extent that regular income taxes exceed the alternative minimum tax in any such year.

8. Commitments and Contingencies

Lease Commitments

The Company leases certain transportation vehicles, warehouse facilities, office space, and machinery and equipment under cancelable and non-cancelable leases. Leases for the Company's offices in Houston and Denver each run for approximately seven more years. With the acquisition of Cody Company in August 2001, the Company assumed certain lease agreements, most of which expire in 2004. Most of the other leases expire within five years and may be renewed. Rent expense under such arrangements totaled $8.8 million, $7.7 million, and $6.3 million for the years ended December 31, 2002, 2001, and 2000, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2002 are as follows:

(In thousands)	
2003	$ 5,590
2004	4,805
2005	4,419
2006	3,732
2007	3,488
Thereafter	5,119
	$ 27,153

Contingencies

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

Environmental Liability

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

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

A group of potentially responsible parties, including the Company, formed a group, called the Casmalia Negotiating Committee ("CNC"). The CNC has had extensive settlement discussions with the EPA and has entered into a consent decree, which will require the CNC to pay approximately $27 million toward Site clean up in return for a release from liability. On January 30, 2002, the Company placed $1,283,283 in an escrow account, representing its volumetric share of the CNC/United States settlement. This cash settlement, once released from escrow and paid to the federal government after the consent decree is entered by the court, will resolve all federal claims against the Company for response costs and will release the Company from all response costs related to the Site, except for future claims against the Company for natural resource damage, unknown conditions, transshipment risks and claims by third parties. Most of the CNC, including the Company, have purchased insurance designed to protect the Company from these liabilities not covered by the consent decree.

The State of California, a third party, has asserted a claim against the CNC and other companies alleged to have waste at Casmalia for costs the State incurred and will incur at the site. The CNC has presented the claim to its insurer. The ultimate disposition of this claim is unknown. However, given the size of the State's claim, and the number of parties allegedly responsible, the Company's share of this claim is expected to be immaterial.

The Company has established a reserve management believes to be adequate to provide for this environmental liability and related legal costs.

Wyoming Royalty Litigation

In June 2000, the Company was sued by two overriding royalty owners in Wyoming state court for unspecified damages. The plaintiffs have requested class certification under the Wyoming Rules of Civil Procedure and allege that the Company has improperly deducted costs of production from royalty payments to the plaintiffs and other similarly situated persons. Additionally, the suit claims that the Company has failed to properly inform the plaintiffs and other similarly situated persons of the deductions taken from royalties. In January 2002, thirteen 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.

Although management believes that a number of the Company's defenses are supported by Wyoming case law, a recent letter decision handed down by a state district court in another case does not support certain of the defenses. The decision has not been reduced to a formal order and it is not known what effect, if any, the decision will have on the pending cases.

In the Company's federal case, the judge recently 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 these cases. The federal judge refused, however, to certify one question on check stub reporting 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. The plaintiffs in the federal case currently claim $5.5 million in damages for the deductions and related issues and $12.9 million in damages for violation of the check stub reporting statute. 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 both the cases. The Company has a reserve that management believes is adequate to provide for these potential liabilities based its estimate of the probable outcome of these matters. Should circumstances change, the potential impact could 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 have 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 $1/8^{th}$ royalty share of the gas sales contract settlement that the Company reached with Columbia in the 1995 Columbia bankruptcy proceeding.

The Company had removed the lawsuit to federal court, however in February 2003 the Company 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. No trial or dispositive motions dates have been set and limited factual discovery is ongoing.

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 Royalty 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, Inc. 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. There is a trial date of May 19, 2003. However, the recent addition of the Company as defendant, as well as others, is expected to lead to a continuance of that trial date. 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, acquired title and since the Company acquired its lease is approximately $12 million. The carrying value of this property is approximately $35 million.

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

9. Cash Flow Information

Cash paid for interest and income taxes is as follows:

	Year Ended December 31,		
(In thousands)	**2002**	2001	2000
Interest	**$ 25,112**	$ 16,295	$ 23,180
Income Taxes	**$ 266**	$ 14,395	$ 1,419

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,		
	2002	2001	2000
Shares Under Option at Beginning of Period	**1,081,621**	1,124,148	1,773,389
Granted	**429,300**	454,100	299,250
Exercised	**181,027**	408,949	896,081
Surrendered or Expired	**42,065**	87,678	52,410
Shares Under Option at End of Period	**1,287,829**	1,081,621	1,124,148
Options Exercisable at End of Period	**570,406**	355,778	474,599

For each of the three most recent years, the price range for outstanding options was $15.25 to $27.30 per share. The following tables provide more information about the options by exercise price and year.

Options with exercise prices between $15.25 and $20.00 per share:

	December 31,		
	2002	2001	2000
Options Outstanding			
Number of Options	**737,385**	480,561	866,498
Weighted Average Exercise Price	**$ 18.97**	$ 17.79	$ 17.63
Weighted Average Contractual Term (in years)	**3.0**	1.50	2.60
Options Exercisable			
Number of Options	**301,277**	211,734	372,418
Weighted Average Exercise Price	**$ 18.39**	$ 17.29	$ 16.27

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

	December 31, 2002	2001	2000
Options Outstanding			
Number of Options	**550,444**	601,060	257,650
Weighted Average Exercise Price	**$ 25.81**	$ 25.44	$ 22.46
Weighted Average Contractual Term (in years)	**3.0**	4.30	1.90
Options Exercisable			
Number of Options	**269,129**	144,044	102,181
Weighted Average Exercise Price	**$ 25.39**	$ 22.45	$ 22.51

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 Company has opted to continue using the intrinsic value based method, as recommended by Accounting Principles Board (APB) Opinion No. 25, to measure compensation cost for its stock option plans.

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)	2002	2001	2000
Net Income, as reported	**$ 16,103**	$ 47,084	$ 29,221
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax	**1,605**	1,355	1,051
Pro forma net income	**$ 14,498**	$ 45,729	$ 28,170
Earnings per share:			
Basic – as reported	**$ 0.51**	$ 1.56	$ 1.07
Basic – pro forma	**$ 0.46**	$ 1.51	$ 1.03
Diluted – as reported	**$ 0.50**	$ 1.53	$ 1.06
Diluted – pro forma	**$ 0.45**	$ 1.49	$ 1.02

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)	2002	2001	2000
Compensation Expense in Net Income, as reported(1)	**$ 2,326**	$ 1,078	$ 595
Weighted Average Value of Options Granted During the Year(2)	**$ 6.23**	$ 8.61	$6.63
Assumptions			
Stock Price Volatility	**35.8%**	34.9%	34.5%
Risk Free Rate of Return	**3.9%**	4.7%	5.2%
Dividend Rate (per year)	**$ 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 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.

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, 2002, and 2001, there were no shares of Junior Preferred Stock issued or outstanding.

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

Preferred Stock

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

In October 1999, Cabot Oil & Gas agreed with the holder of the 6% preferred stock that the Company would repurchase all the 6% preferred stock for $51.6 million in cash or Class A common stock. During the second quarter of 2000, the Company completed this repurchase and paid the holder of the preferred stock $51.6 million in cash. The cash payment was funded using a portion of the proceeds from the issuance of 3,400,000 shares of Class A common stock in a registered offering at a price of $21.50 per share (yielding net proceeds of $71.5 million, after expenses). The remaining proceeds of this offering of Class A common stock were used to reduce borrowings under the revolving credit facility.

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

11. Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the consolidated balance sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value. The Company uses available marketing data and valuation methodologies to estimate fair value of debt. 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, 2002		December 31, 2001	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Debt				
7.19% Notes	$ 100,000	$ 113,591	$ 100,000	$ 104,961
7.26% Notes	75,000	84,231	75,000	79,187
7.36% Notes	75,000	86,461	75,000	79,225
7.46% Notes	20,000	23,322	20,000	21,097
Credit Facility	95,000	95,000	123,000	123,000
	$ 365,000	$ 402,605	$ 393,000	$ 407,470

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.

Commodity Price Swaps and Options

Hedges on Production - Swaps

From time to time, the Company enters into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of its production. These derivatives are not held for trading purposes. Under these price swaps, the Company receives a fixed price on a notional quantity of natural gas and crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures. Under the Revolving Credit Agreement the aggregate level of commodity hedging must not exceed 80% of the anticipated future production during the period covered by the hedges. During 2002, the Company fixed the price at an average of $4.44 per Mcf on quantities totaling 7,870 Mmcf, representing 11% of the Company's 2002 natural gas production. The Company did not have crude oil swap arrangements covering its production in 2002. During 2001, the Company fixed the price at an average of $3.75 per Mcf on quantities totaling 918 Mmcf, representing approximately 1% of the Company's 2001 natural gas production. The Company did not have crude oil swap arrangements covering its production in 2001. During 2000, the Company fixed the price at an average of $4.54 per Mcf on quantities totaling 315 Mmcf, representing less than 1% of the Company's 2000 natural gas production. The Company did not have crude oil swap arrangements covering its production in 2000.

As of the years ended December 31, 2002, and 2001, the Company had no crude oil swap contracts that qualified as hedges outstanding. The Company had open natural gas price swap contracts on its production as follows:

	Natural Gas Price Swaps		
Contract Period	Volume in Mmcf	Weighted Average Contract Price	Unrealized Loss *(In $ millions)*
As of December 31, 2002			
Natural Gas Price Swaps on Production in:			
First Quarter of 2003	8,333	$ 4.44	
Second Quarter of 2003	7,107	4.24	
Third Quarter of 2003	7,186	4.24	
Fourth Quarter of 2003	7,186	4.24	
Full Year of 2003	**29,812**	**4.29**	**$ 15,062**
First Quarter of 2004	2,089	$ 4.42	
Second Quarter of 2004	2,089	4.42	
Third Quarter of 2004	2,112	4.42	
Fourth Quarter of 2004	2,112	4.42	
Full Year of 2004	**8,402**	**4.42**	**$ 1,753**
As of December 31, 2001			
None			

Natural gas price swaps increased revenue by $0.9 million in 2002 and reduced revenue by $0.8 million in 2001.

From time to time the Company enters into crude oil range swaps with counterparties. These derivatives do not qualify for hedge accounting under SFAS 133 and are recorded at fair value at the balance sheet date. The Company entered into two derivative arrangements as follows:

- A fixed price swap at $28.15 per barrel, unless the NYMEX West Texas Intermediate monthly average price falls below $21.00 per barrel. If the NYMEX West Texas Intermediate monthly average price falls below $21.00 per barrel for any month, the swap is cancelled for that month. This instrument covers 730 Mbbls of production over the period January 2003 through December 2003.
- A fixed price swap at $27.75 per barrel, unless the NYMEX West Texas Intermediate monthly average price falls below $21.00 per barrel. If the NYMEX West Texas Intermediate monthly average price falls below $21.00 per barrel for any month, the swap is cancelled for that month. This instrument covers 276 Mbbls of production over the period July 2003 through December 2003.

The crude oil range swaps at December 31, 2002, had a pre-tax unrealized loss in the amount of $0.7 million, which is reflected in crude oil operating revenue, and covered approximately 31% of the Company's anticipated crude oil production during this period. The Company had no crude oil range swap contracts outstanding during 2001.

Hedges on Production - Options

In December 2001 and March 2002, management believed that the pricing environment provided a strategic opportunity to significantly reduce the price risk on a portion of the Company's 2002 production through the use of a series of collars. Under the collar arrangements, if the index rises above the ceiling price, the Company pays the counterparty. If the applicable index falls below the floor, the counterparty pays the Company. The 2002 natural gas price hedges include several collar arrangements based on nine price indexes. The first series of natural gas price collars were in place for the months of January through April 2002 with a weighted average price floor of $2.68 per Mcf and a weighted average price ceiling of $3.53 per Mcf. These hedges covered 16,145 Mmcf, or 22% of the Company's natural gas production for the year. The second series of natural gas price collars were in place for the months of May through August 2002 with a weighted average price floor of $2.54 per Mcf and a weighted average price ceiling of $3.17 per Mcf. These hedges covered 18,284 Mmcf, or 25% of the Company's natural gas production for the year.

All indexes were within the collars during the month of January, all were below the floor for February through March, and most were above the ceiling in April through August, resulting in a cash expenditure of $1.4 million for the year. Overall, the natural gas collar and swap arrangements resulted in a reduction of $0.01 per Mcf to the Company's average realized natural gas price for 2002.

During 2001, the Company used several costless collar arrangements to hedge a portion of its 2001 natural gas production. The 2001 natural gas price hedges include several costless collar arrangements based on eight price indexes at which the Company sells a portion of its production. These hedges were in place for the months of February through October 2001 and covered 24,404 Mmcf, or 35%, of the Company's natural gas production for the year. All indexes were within the collars during February and April, some fell below the floor during the period of March, and all indexes were below the floor from June through October, resulting in a $34.6 million cash revenue for the year. These gains contributed $0.50 per Mcf to the Company's average realized natural gas price for 2001.

Again in August 2002, management believed that the pricing environment provided a strategic opportunity to significantly reduce the price risk on a portion of the Company's 2003 production through the use of natural gas price collar arrangements. As of the years ended December 31, 2002, and 2001, the Company had open natural gas price collar contracts on its production as follows:

	Natural Gas Price Collars		
Contract Period	Volume in Mmcf	Weighted Average Ceiling / Floor	Unrealized Loss *(In $ millions)*
As of December 31, 2002			
Natural Gas Costless Collars on Production in:			
First Quarter of 2003	2,066	$ 5.03/$4.36	
Second Quarter of 2003	2,089	$ 5.03/$4.36	
Third Quarter of 2003	2,112	$ 5.03/$4.36	
Fourth Quarter of 2003	2,112	$ 5.03/$4.36	
Full Year of 2003	**8,379**	**$ 5.03/$4.36**	**$ 2,090**
As of December 31, 2001			
Natural Gas Costless Collars on Production in:			
First Quarter of 2002	12,082	$ 3.54/$2.68	
Second Quarter of 2002	4,027	$ 3.54/$2.68	
Full Year of 2003	**16,109**	**$ 3.54/$2.68**	—

The natural gas price collars open at December 31, 2002 include collar arrangements based on two price indexes at which the Company sells a portion of its production. These hedges are in place for the full year of 2003 and cover approximately 11% of the Company's anticipated natural gas production during this period. The Company also has crude oil collars open at December 31, 2002. These hedges are in place for the months of January through June 2003 with a weighted average price floor of $24.75 and a weighted average price ceiling of $28.86. These hedges cover approximately 11% of the Company's anticipated crude oil production during this period. Crude oil collars reduced revenue by $5.2 million during 2002, but had no impact on 2001 results.

Subsequent to year end the Company entered into a series of natural gas costless collar and natural gas and crude oil price swap arrangements to significantly reduce the price risk on a portion of its 2003 and 2004 production. These arrangements are as follows:

- A natural gas costless collar in place for the months of February through December 2003 with a weighted average price floor of $4.71 per Mcf and a weighted average price ceiling of $5.98 per Mcf. This hedge covers 6,386 Mmcf of our anticipated natural gas production for the year.
- A natural gas costless collar in place for the full year of 2004 with a weighted average price floor of $4.33 per Mcf and a weighted average price ceiling of $5.42 per Mcf. This hedge covers 5,041 Mmcf of our anticipated natural gas production for the year.
- A natural gas costless collar in place for the full year of 2004 with a weighted average price floor of $4.16 per Mcf and a weighted average price ceiling of $5.25 per Mcf. This hedge covers 3,346 Mmcf of our anticipated natural gas production for the year.
- A natural gas costless collar in place for the months of March through December 2003 with a weighted average price floor of $3.91 per Mcf and a weighted average price ceiling of $5.08 per Mcf. This hedge covers 1,371 Mmcf of our anticipated natural gas production for the year.
- A natural gas price swap in place for the months of March through December 2003 with a fixed price of $4.46 per Mcf. This hedge covers 1,371 Mmcf of our anticipated natural gas production for the year.

- A fixed price swap at $30.00 per barrel, unless the NYMEX West Texas Intermediate monthly average price falls below $22.00 per barrel. If the NYMEX West Texas Intermediate monthly average falls below $22.00 per barrel for any month, the swap is cancelled for that month. This instrument covers 92 Mbbls of production over the period July 2003 through December 2003.

Adoption of SFAS 133

The Company adopted SFAS 133, "*Accounting for Derivative Instruments and Hedging Activities*," 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.

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

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

As of December 31, 2001, the Company had a series of nine natural gas price collar arrangements outstanding. As of December 31, 2002 the Company had a series of 16 natural gas price swap arrangements, two natural gas price collar arrangements, two crude oil price collar arrangements, and two crude oil swap arrangements outstanding. In accordance with the latest guidance from the FASB's Derivative Implementation Group, the Company tests the effectiveness of the combined intrinsic and time values and the effective portion of each will be recorded as a component of Other Comprehensive Income. Any ineffective portion will be recorded as a gain or loss in the current period. As of December 31, 2002, the Company had recorded $18.8 million of Other Comprehensive Loss ($11.6 million net of deferred taxes), a $0.6 million Unrealized Hedge Loss in revenue, a $0.6 million Hedge Asset, and a $20.0 million Hedge Liability, exclusive of the crude oil range swaps. As of December 31, 2001, the Company had recorded $1.4 million of Other Comprehensive Income ($0.8 million net of deferred taxes), a $0.1 million Unrealized Hedge Gain in revenue and a $1.5 million Hedge Asset.

Other Comprehensive Income

Comprehensive income includes net income and certain items recorded directly to stockholders' equity and classified as Other Comprehensive Income. The Company recorded Other Comprehensive Income for the first time in January of 2001. Following the adoption of SFAS 133, the Company recorded an after-tax credit to Other Comprehensive Income of $0.8 million in 2001 related to the change in fair value of certain derivative financial instruments that has qualified for cash flow hedge accounting. As of December 31, 2002, the Company had recorded $22.3 million of Other Comprehensive Loss ($13.8 million net of deferred taxes). Amounts recorded consisted of a $6.4 million loss for Reclassification Adjustments for Settled Contracts ($4.0 million net of deferred taxes), a $13.7 million loss for Changes in Fair Value of Outstanding Hedge Positions ($8.5 million net of deferred taxes), and a $2.2 million loss for an Adjustment to Recognize Minimum Pension Liability ($1.3 million net of deferred taxes).

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 2002, approximately 14% of the Company's total sales were made to one customer. This customer operates certain properties in which the Company has interests in the Gulf Coast and purchases all of the production from these wells. This customer is currently reselling 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 the Company's portion of the production. The Company had no sales to any customer that exceeded 10% of its total gross revenues in 2001 or 2000.

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 more 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 January 1, 2003 there are no assets legally restricted for purposes of settling asset retirement obligations. The Company will record a net-of-tax cumulative effect of change in accounting principle loss, in January of 2003, of approximately $6.8 million and record a retirement obligation of approximately $35.1 million. There will be no impact on the Company's cash flows as a result of adopting SFAS 143.

13. Other Revenue

Settlement of Contract Dispute

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

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

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

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

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. Revenue from these monetized credits was $2.0 million in 2002, $2.0 million in 2001, and $2.2 million in 2000. 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 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 values 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 has been prepared to give effect to the Cody acquisition as if it had occurred on January 1, 2001. The information presented is not necessarily indicative of the results of future operations of the Company.

	Year Ended December 31,	
(In thousands)	**2002**	2001
Revenues	**$ 353,756**	$ 505,528
Net Income	**$ 16,103**	$ 54,513
per share - Basic	**$ 0.51**	$ 1.75
per share - Diluted	**$ 0.50**	$ 1.73

The decrease in revenues from 2001 to 2002 is primarily the result of lower realized prices both for natural gas and crude oil. The Company's realized natural gas price declined by 31% and crude oil prices declined by 4%. Partially offsetting the decline in revenues were lower operating expenses, including brokered gas cost and exploration expense, as well as a reduction in income tax expense. The results of operations for Cody Company are consolidated with Cabot Oil & Gas Corporation as of August 1, 2001.

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. The Company's current interest in Kurten is approximately 25%, including a one percent interest in the partnership. Under the partnership agreement, the Company has the right to a reversionary working interest that would bring its ultimate interest to 50% upon the limited partner reaching payout. Under the partnership agreement, the limited partner has the sole 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 has been 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 our decision to proceed with the liquidation, the Company performed an impairment review which resulted in an after-tax charge of approximately $55 million. This impairment charge will be reflected in the first quarter of 2003 as an operating expense but does not impact the Company's cash flows. In addition, the Company will record a downward reserve revision of approximately 16 Bcfe as a result of the loss of the reversionary interest.

15. Earnings per Common Share

Full year basic earnings per share for the Company were $0.51, $1.56, and $1.07 in 2002, 2001, and 2000, respectively, and were based on the weighted average shares outstanding of 31,736,975 in 2002, 30,275,906 in 2001, and 27,383,848 in 2000. Diluted earnings per share for the Company were $0.50, $1.53, and $1.06 in 2002, 2001, and 2000, respectively. The diluted earnings per share amounts are based on weighted average shares outstanding plus common stock equivalents. Common stock equivalents include stock awards and stock options, and totaled 338,972 in 2002, 408,361 in 2001, and 281,210 in 2000. Stock awards and stock options excluded from the calculation of diluted earnings per share because the effect was antidilutive were 1,174,507, 913,310, and 947,909 in 2002, 2001 and 2000, respectively.

No preferred stock was outstanding at the end of 2002, 2001 or 2000. See Note 10, "*Capital Stock*" for further discussion.

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, 2002, 2001, and 2000 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 7, 2003, 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, 2002, 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)	**2002**	2001	2000
Proved Reserves			
Beginning of Year	**1,036,004**	959,222	929,602
Revisions of Prior Estimates	**14,405**	(44,266)	(14,796)
Extensions, Discoveries and Other Additions	**64,945**	99,911	103,600
Production	**(73,670)**	(69,162)	(60,934)
Purchases of Reserves in Place	**26,262**	91,290	5,118
Sales of Reserves in Place	**(6,987)**	(991)	(3,368)
End of Year	**1,060,959**	1,036,004	959,222
Proved Developed Reserves	**819,412**	804,646	754,962
Percentage of Reserves Developed	**77.2%**	77.7%	78.7%

(Thousands of barrels)	Liquids December 31, 2002	2001	2000
Proved Reserves			
Beginning of Year	**19,684**	9,914	8,189
Revisions of Prior Estimates	**1,871**	254	562
Extensions, Discoveries and Other Additions	**851**	2,257	2,032
Production	**(2,909)**	(1,996)	(988)
Purchases of Reserves in Place	**261**	9,255	120
Sales of Reserves in Place	**(1,365)**	—	(1)
End of Year	**18,393**	19,684	9,914
Proved Developed Reserves	**13,267**	15,328	8,438
Percentage of Reserves Developed	**72.1%**	77.9%	85.1%

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.

(In thousands)	Year Ended December 31, 2002	2001	2000
Aggregate Capitalized Costs Relating to Oil and Gas Producing Activities	**$1,704,746**	$1,632,101	$1,180,692
Aggregate Accumulated Depreciation, Depletion and Amortization	**$ 750,857**	$ 651,657	$ 558,463

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

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

(In thousands)	Year Ended December 31, 2002	2001	2000
Property Acquisition Costs, Proved[1]	**$ 8,799**	$ 245,079	$ 5,954
Property Acquisition Costs, Unproved[1]	**4,869**	21,116	10,869
Exploration and Extension Well Costs[2]	**52,012**	91,261	40,008
Development Costs	**55,165**	90,246	59,879
Total Costs	**$ 120,845**	$ 447,702	$ 116,710

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

(2) *Includes administrative exploration costs of $8,942, $9,831, and $8,442 for the years ended December 31, 2002, 2001, and 2000, 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:

	Year Ended December 31,		
(In thousands)	**2002**	2001	2000
Operating Revenues	**$ 280,379**	$ 339,064	$ 214,116
Costs and Expenses			
Production	**63,823**	58,382	46,721
Other Operating	**21,731**	22,656	17,249
Exploration(1)	**40,167**	71,165	19,858
Depreciation, Depletion and Amortization	**102,086**	89,286	63,200
Total Costs and Expenses	**227,807**	241,489	147,028
Income Before Income Taxes	**52,572**	97,575	67,088
Provision for Income Taxes	**18,400**	34,151	23,481
Results of Operations	**$ 34,172**	$ 63,424	$ 43,607

(1) *Includes administrative exploration costs of $8,942, $9,831, and $8,442 for the years ended December 31, 2002, 2001, and 2000, 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, 2002, 2001, and 2000 for natural gas ($ per Mcf) were $4.41, $2.65, and $9.63, respectively, and for oil ($ per Bbl) were $30.39, $18.56, and $26.18, 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, 2002[1]	2001[1]	2000[1]
Future Cash Inflows	**$ 5,236,349**	$ 3,107,668	$ 9,497,181
Future Production Costs	**(1,137,615)**	(823,988)	(1,435,489)
Future Development Costs	**(284,165)**	(266,833)	(192,893)
Future Net Cash Flows Before Income Taxes	**3,814,569**	2,016,847	7,868,799
10% Annual Discount for Estimated Timing of Cash Flows	**(2,098,669)**	(1,065,747)	(4,332,551)
Standardized Measure of Discounted Future Net Cash Flows Before Income Taxes	**1,715,900**	951,100	3,536,248
Future Income Tax Expenses, Net of 10% Annual Discount[2]	**(460,547)**	(185,074)	(1,126,416)
Standardized Measure of Discounted Future Net Cash Flows	**$ 1,255,353**	$ 766,026	$ 2,409,832

[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 $1,195,082, $558,085, and $2,642,810 for the years ended December 31, 2002, 2001, and 2000, 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, 2002	2001	2000
Beginning of Year	**$ 766,026**	$ 2,409,832	$ 587,557
Discoveries and Extensions, Net of Related Future Costs	**112,269**	100,084	486,236
Net Changes in Prices and Production Costs[1]	**703,874**	(2,545,349)	2,441,921
Accretion of Discount	**95,110**	353,625	73,782
Revisions of Previous Quantity Estimates, Timing and Other	**51,944**	(358,134)	(81,093)
Development Costs Incurred	**20,516**	26,158	28,540
Sales and Transfers, Net of Production Costs	**(216,555)**	(280,682)	(167,395)
Net Purchases (Sales) of Reserves in Place	**(2,357)**	119,149	16,440
Net Change in Income Taxes	**(275,474)**	941,343	(976,156)
End of Year	**$ 1,255,353**	$ 766,026	$ 2,409,832

[1] *For 2000, the prices for natural gas used in this calculation were regional cash price quotes on the last day of the year. These prices were higher than the Company actually realized in December 2000. Further, based on market conditions in February 2001, the prices are not indicative of those that the Company expects to realize consistently in the future. For 2001, year-end pricing returned to the range that management considers typical.*

SELECTED DATA (UNAUDITED)

QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

(In thousands, except per share amounts)	First	Second	Third	Fourth	Total
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	**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**
2001					
Operating Revenues	$ 154,891	$ 107,606	$ 104,226	$ 80,319	$ 447,042
Impairment of Long-Lived Assets	—	—	1,721	5,131	6,852
Operating Income (Loss)	68,526	26,976	21,601	(21,737)	95,366
Net Income (Loss)	39,062	13,593	10,031	(15,602)	47,084
Basic Earnings per Share	$ 1.33	$ 0.46	$ 0.33	$ (0.49)	$ 1.56
Diluted Earnings per Share	$ 1.32	$ 0.45	$ 0.32	$ (0.49)	$ 1.53

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information under the caption “Election of Directors” in the Company’s definitive Proxy Statement in connection with the 2002 annual stockholders’ meeting is incorporated by reference.

ITEM 11. EXECUTIVE COMPENSATION

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

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

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

Equity Compensation Plan Information

The following table provides information as of December 31, 2002 regarding the number of shares of Common Stock that may be issued under the Company's equity compensation plans. All of the Company's equity compensation plans have been approved by the Company's stockholders.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	1,287,829	$21.89	1,169,979[1]
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	**1,287,829**	**$21.89**	**1,169,979[1]**

[1] *Includes 225,650 shares of restricted stock awarded under the Second Amended and Restated 1994 Long Term Incentive Plan, the restrictions on which lapse over the period 2003, 2004 and 2005.*

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

ITEM 14. CONTROLS AND PROCEDURES

Within the 90-day period prior to the date of this report, 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 Rule 13a-14 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 IV

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

A. INDEX

1. Consolidated Financial Statements

See Index on page 49.

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).
4.6	Note Purchase Agreement dated May 11, 1990, among the Company and certain insurance companies parties thereto (Form 10-Q for the quarter ended June 30, 1990). (a) First Amendment dated June 28, 1991 (Form 10-K for 1994). (b) Second Amendment dated July 6, 1994 (Form 10-K for 1994).
4.7	Note Purchase Agreement dated November 14, 1997, among the Company and the purchasers named therein (Form 10-K for 1997).
4.8	Note Purchase Agreement dated as of July 26, 2001 among Cabot Oil & Gas Corporation and the Purchasers listed therein (Form 8-K for August 30, 2001).
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
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 dated February 7, 2003.

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 18th of February 2003.

CABOT OIL & GAS CORPORATION

By: /s/ Dan O. Dinges
Dan O. Dinges
Chairman of the Board,
Chief Executive Officer, and President

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

Signature	Title	Date
/s/ Dan O. Dinges Dan O. Dinges	Chairman of the Board, Chief Executive Officer, and President (Principal Executive Officer)	February 18, 2003
/s/ Scott C. Schroeder Scott C. Schroeder	Vice President, Chief Financial Officer (Principal Financial Officer)	February 18, 2003
/s/ Henry C. Smyth Henry C. Smyth	Vice President, Controller and Treasurer (Principal Accounting Officer)	February 18, 2003
/s/ Robert F. Bailey Robert F. Bailey	Director	February 18, 2003
/s/ Henry O. Boswell Henry O. Boswell	Director	February 18, 2003
/s/ John G. L. Cabot John G. L. Cabot	Director	February 18, 2003
/s/ James G. Floyd James G. Floyd	Director	February 18, 2003
/s/ C. Wayne Nance C. Wayne Nance	Director	February 18, 2003
/s/ P. Dexter Peacock P. Dexter Peacock	Director	February 18, 2003
/s/ Arthur L. Smith Arthur L. Smith	Director	February 18, 2003
/s/ William P. Vititoe William P. Vititoe	Director	February 18, 2003

CERTIFICATIONS

I, Dan O. Dinges, certify that:

1. I have reviewed this annual report on Form 10-K of Cabot Oil & Gas Corporation;

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

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

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

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

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

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

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

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

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

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 21, 2003

/s/ Dan O. Dinges

Dan O. Dinges
Chairman of the Board,
Chief Executive Officer, and President

I, Scott C. Schroeder, certify that:

1. I have reviewed this annual report on Form 10-K of Cabot Oil & Gas Corporation;

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

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

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

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

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

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

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

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

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

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 21, 2003

/s/ Scott C. Schroeder

Scott C. Schroeder
Vice President and Chief Financial Officer

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Corporate Information

Officers

Dan O. Dinges
Chairman of the Board,
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

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

COG Listed NYSE
THE NEW YORK STOCK EXCHANGE

Annual Meeting

The annual meeting of shareholders will be held Tuesday, April 29, 2003, at 10:00 a.m. (CDT) at the corporate office in Houston, Texas.

Corporate Office

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Houston, Texas 77077
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Houston, Texas 77210-4544
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Independent Accountants

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

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Receive and Deliver Department
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Cabot Oil & Gas Corporation