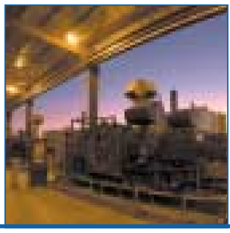
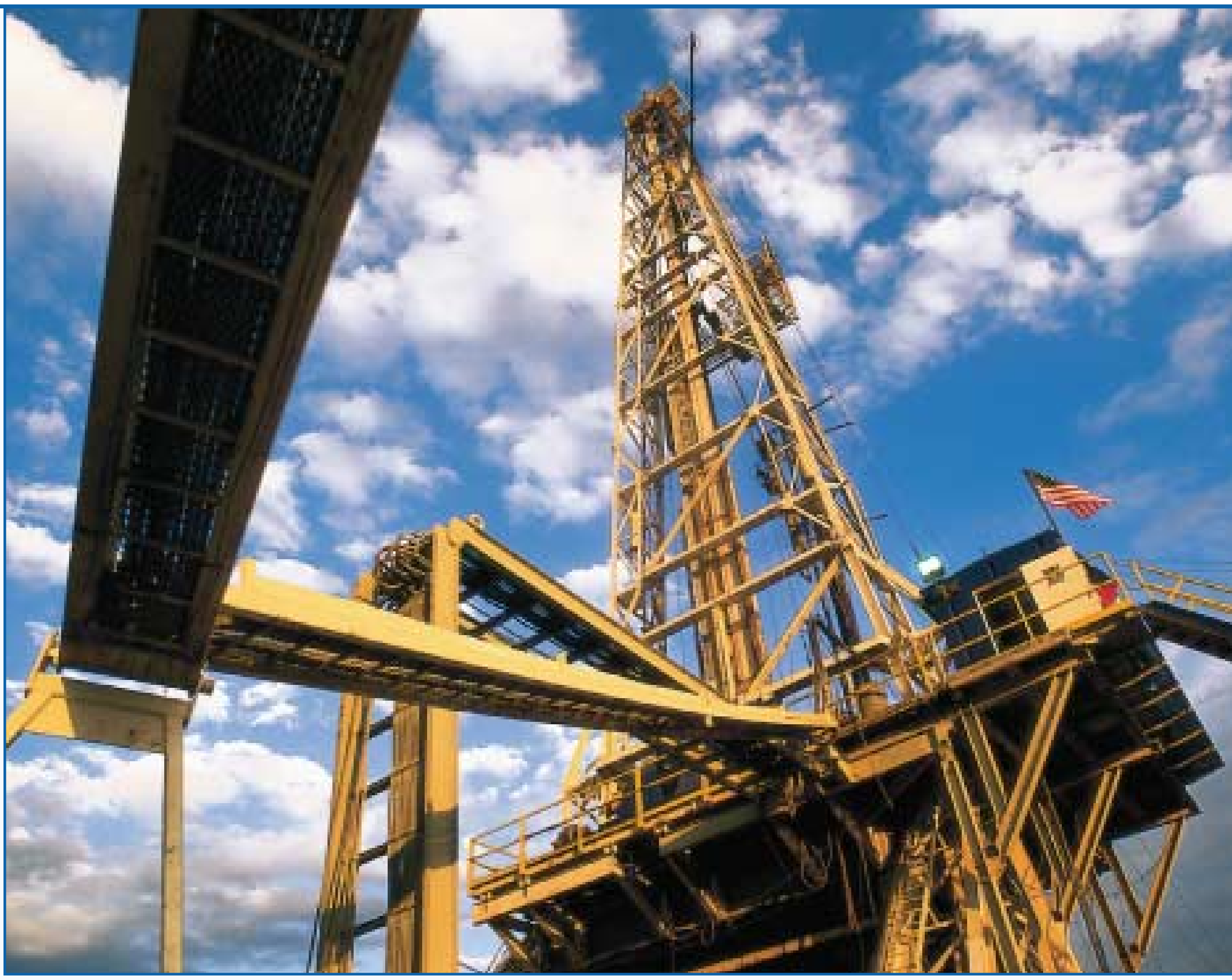
   

2004 Annual Report

Balance

Cabot Oil & Gas Corporation

On the front cover, we illustrate the *Balance* achieved through portfolio diversification that stretches from Canada to West Virginia. Cabot Oil & Gas Corporation is engaged in the exploration, development, acquisition and exploitation of oil and gas properties. The Company is a leading domestic energy producer with substantial interests in the Texas and Louisiana Gulf Coast, the Western region with operations in the Rocky Mountains and Mid-Continent, the Eastern region and a new position in Canada.



Above: Onshore Gulf Coast drilling activity.

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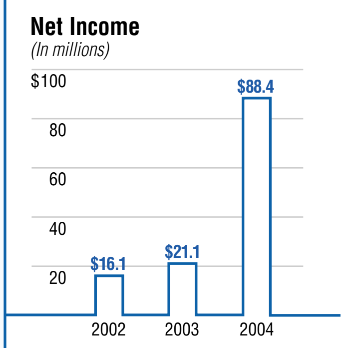
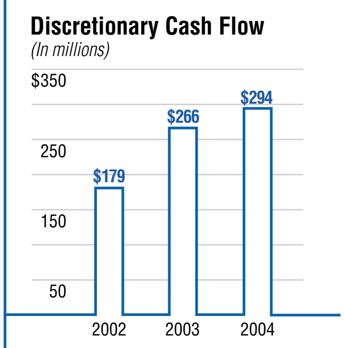
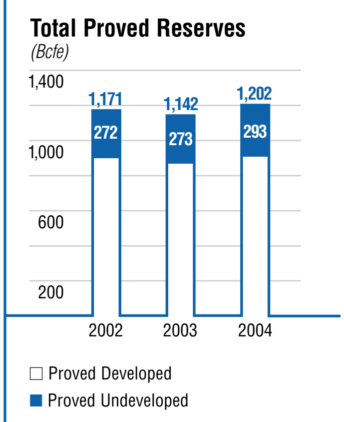
Financial Highlights

	Year Ended December 31, 2002	2003	2004
Financial Data *(In millions, except share amounts)*			
Operating Revenues	$ 353.8	$ 509.4	**$ 530.4**
Net Income	$ 16.1	$ 21.1	**$ 88.4**
Per Share	$ 0.51	$ 0.66	**$ 2.72**
Discretionary Cash Flow[1]	$ 178.8	$ 266.4	**$ 294.3**
Per Share	$ 5.63	$ 8.31	**$ 9.06**
Capital and Exploration Expenditures	$ 126.3	$ 188.2	**$ 259.5**
Common Dividends per Share	$ 0.16	$ 0.16	**$ 0.16**
Average Common Shares Outstanding *(In thousands)*	31,737	32,050	**32,488**
Capitalization *(In millions)*			
Long-term Debt	$ 365.0	$ 270.0	**$ 250.0**
Shareholders' Equity *(Successful Efforts Method)*	$ 350.7	$ 365.2	**$ 455.7**
Annual Production Volume			
Bcfe	91.1	89.0	**84.8**
% Growth	12%	(2%)	**(5%)**
% Gas	81%	81%	**86%**
Proved Reserves[2]			
Natural Gas *(Bcf)*	1,061.0	1,069.5	**1,134.1**
Oil, Condensate and Natural Gas Liquids *(Mmbbl)*	18.4	12.1	**11.4**
Total Proved *(Bcfe)*	1,171.3	1,142.1	**1,202.4**
Total Developed *(Bcfe)*	899.0	868.7	**909.7**
% Gas	91%	94%	**94%**
% Developed	77%	76%	**76%**
Reserve Life *(Years)*	12.9	12.8	**14.2**
Reserve Additions			
Drilling Additions *(Bcfe)*	70.1	115.8	**147.4**
Drilling Additions, Revisions and Purchases *(Bcfe)*	123.5	113.1	**146.2**
Reserve Replacement %	136%	127%	**172%**
Reserve Replacement Cost – Additions *($ per Mcfe)*	$ 1.46	$ 1.41	**$ 1.63**
Reserve Replacement Cost – Additions, Revisions and Purchases *($ per Mcfe)*	$ 0.90	$ 1.46	**$ 1.67**
Wells Drilled			
Total Gross	108	173	**256**
Total Net	72.2	132.0	**219.8**
Gross Success Rate %	93%	89%	**95%**
Produced Average Natural Gas Sales Price *($ per Mcf)*			
Gulf Coast	$ 3.34	$ 4.78	**$ 5.27**
West	$ 2.39	$ 3.67	**$ 4.75**
East	$ 3.38	$ 5.15	**$ 5.60**
Canada	—	—	**$ 4.69**
Total Company	$ 3.02	$ 4.51	**$ 5.20**
Crude and Condensate Price *($ per Bbl)*	$ 23.79	$ 29.55	**$ 31.55**

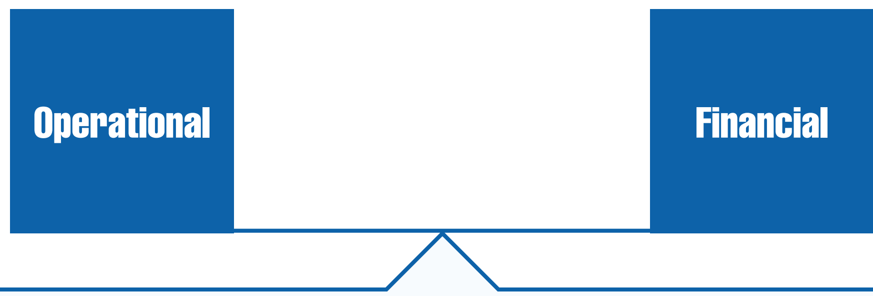






[1] *Net income plus non-cash items from operations and exploration expenses.*

[2] *Changes in reserves from year to year reflect drilling additions and revisions as well as reserves purchased and sold. See Supplemental Oil and Gas Information beginning on page 85 of this report for details.*



Operational: A strategy that measures the comparative merits of each region's projects to find the correct investment balance for growth.

Financial: A strategy that focuses on determining the best capital investment alternatives including reinvestment, repaying debt, dividend policy and stock repurchase programs.

2004 results show unprecedented levels of achievement for many of the key measurements of business success. Following a balanced strategy, the Company delivered to our shareholders record levels for net income, discretionary cash flow, reserves, and most importantly stock price, along with the best year-end capitalization ratio ever for the Company. Our expectation is to continue to deliver record achievement levels in 2005, along with a focus to enhance our production profile.

A balanced strategy, which has been in place since 2002, emphasizes analyzing the merits of each investment, or reinvestment, decision in order to generate long-term value. For the past three years we have been balancing the operational capital requirements with prudent financial strategies, which culminated in exceptional value creation. Part of this success is a direct result of the robust energy environment which, due to concerns over supply of natural gas and oil, continued to drive high commodity price levels, even though near-term supply fundamentals are within historic levels. (See Price Environment, page 6.)

The record highlights include:

- Net income totaled $88.4 million, up 319 percent over last year and almost double the previous record from 2001.
- Discretionary cash flow grew from last year's record of $266.4 million to $294.3 million, a 10 percent increase.
- Total proved reserves exceeded the 1.2 Tcfe level for the first time in the Company's history, with a five percent increase of reserves for the year driven almost entirely by drillbit success.
- An approximate $90 million improvement in equity (driven by results plus option exercises, partially offset by the stock buyback program), allowed the Company to record a debt-to-total capitalization ratio at year-end of 37.2 percent. This ratio represents our lowest in history.
- All of this, together with the market fundamentals, had the impact of a 50 percent increase in the stock price year-over-year.

Other noteworthy accomplishments include:

- Another year of expanded drilling in our East region that yielded a five percent production growth rate and a 400 percent replacement ratio for production.
- The discovery and delineation of another basin-centered gas play in the Rocky Mountains.
- Significant levels of success associated with our initial efforts in Canada, five successes in six attempts.
- Two additional discoveries on the CL&F lease early in 2004, an area we have been operating in since the Company's 1999 discovery of the Etouffee field.

With these successes, and a continued expansion of our East program, along with several impact wells to be drilled in early 2005, we expect to overcome the challenge to increase our overall production levels. Though we generated sufficient cash flow in 2004 to further increase our drilling program, we elected to repurchase 405,100 shares of Cabot stock at an average price of $38.58 per share, another efficient use of capital. We also directed our investments toward longer life basins with less emphasis on shorter life assets.

In making these decisions we did anticipate lower production levels; however, delays in the schedule of several operations, some well performance issues and the effects of Hurricane Ivan reduced our production levels below our expectations. We do believe the eventual long-term impact of our decisions will result in an increasing production profile characterized by less volatility and lower decline rates.

While I am disappointed in the magnitude of the cost to comply with the new Sarbanes-Oxley Section 404 regulation ($2.4 million), I am extremely pleased with the outcome. During this process the level of findings was minimal and we were able to remediate each very quickly. These results highlight the fundamentally sound, conservative culture that Cabot has embraced for years.

All in all, 2004 provided many new milestones for the organization and was yet another step in our effort to build long-term value for our shareholders. (See Strategic Initiatives, page 8.)

2005 and Beyond

For 2005, we have budgeted an expanded capital program for the third consecutive year based on continued strength in the commodity price environment. To ensure our ability to accomplish our program we have hedged approximately 47 percent of our anticipated production for 2005. The hedges are in the form of swaps (about 57 percent) and collars (about 43 percent).

The budget for our program is approximately $280 million, up eight percent from 2004, with nearly 300 wells planned to be drilled. This will be our largest program ever. Of the total drilling program, 32 exploration wells are focused on new horizons. Total net unrisked exposure for our impact prospects is greater than 500 Bcfe. Two hundred of the total wells are to be drilled in the East region, where we have a 97 plus percent historic success rate. (See Commodity Plays, page 10).

Additionally, we are planning for $20 million in debt reductions and the repurchase of COG stock using the budgeted free cash flow. The goal of the buyback program is to, at a minimum, repurchase at least as many shares that are placed in the market under our incentive programs, to prevent shareholder dilution.

2004 will be remembered for its record-setting pace for net income, cash flow from operations, discretionary cash flow, total proved reserves and lowest debt to total capitalization ratio, along with – most importantly – the stock continually testing new highs throughout the year.

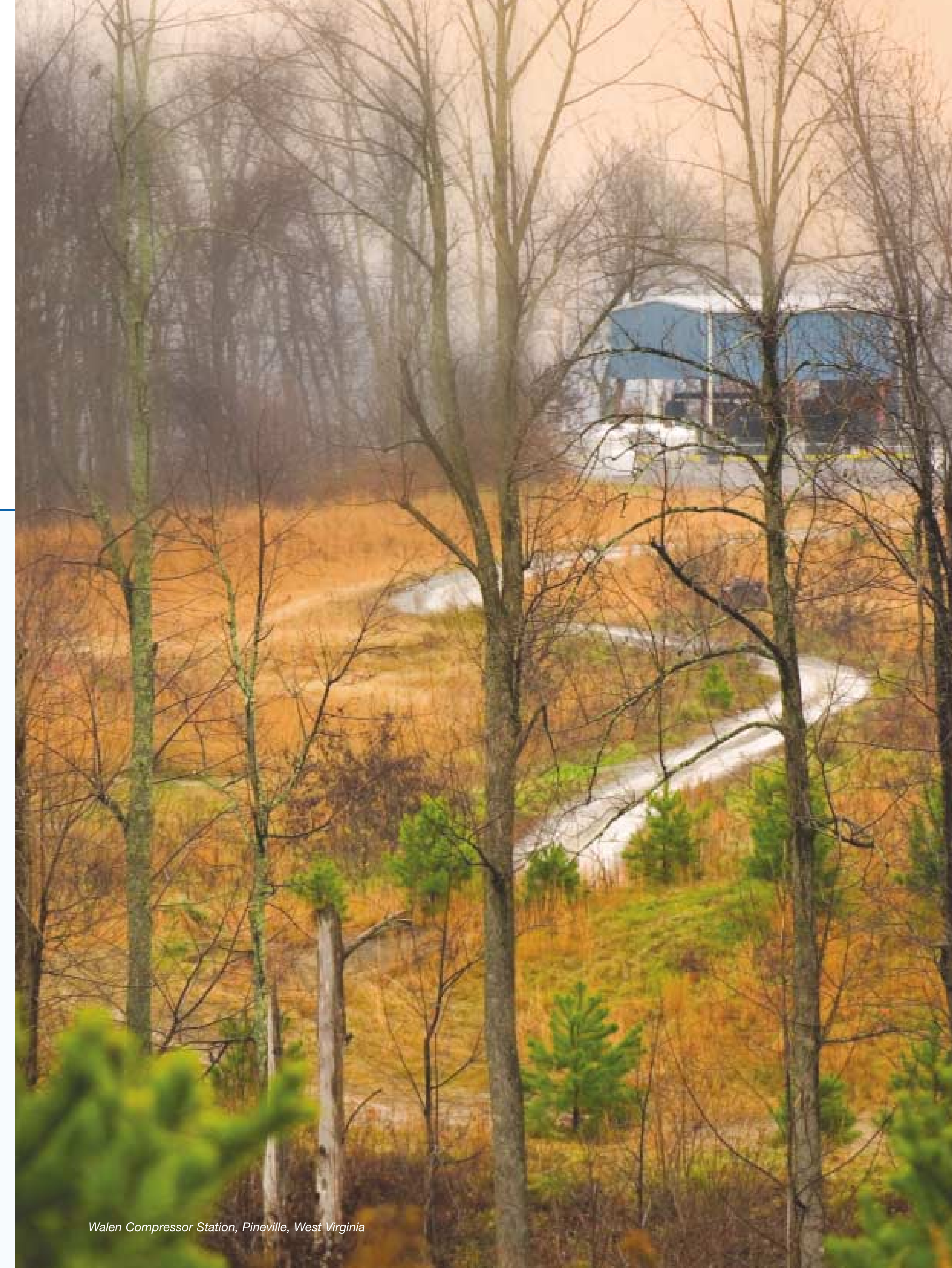
We will continue to be active in the acquisition market; however, we will not jeopardize our long-term objectives for short-term gains. In 2004 we evaluated over 70 different deals and made only two small acquisitions in the East region due to the nature of the market.

Cabot Oil & Gas offers to our shareholders a unique blend of annuity type, legacy assets with planned growth, and assets with impactful new opportunities that can successfully provide years of additional growth. Our North American based portfolio consistently generates cash flow greater than that necessary to replace our annual production and grows the Company assets. Our employees are cost conscious in their efforts to deliver high margin returns. Cabot will continue to balance our unique assets to create value added results both operationally and financially. On behalf of our Board of Directors and employees, thank you for your continued support. We look forward to 2005 as another step toward maximizing shareholder returns.

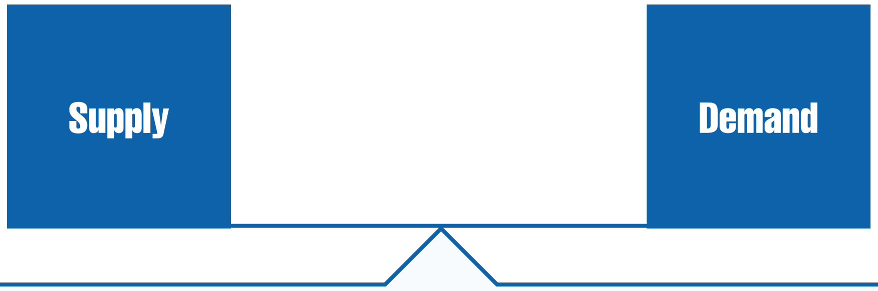
Sincerely,

Dan O. Dinges

Dan O. Dinges
Chairman, President and Chief Executive Officer



Walen Compressor Station, Pineville, West Virginia



The year 2004 began with some of its coldest weather, sending NYMEX gas future prices to record levels. However, temperatures were unusually mild during the remainder of the year, resulting in a sharp reduction in gas demand and a rapid replenishment of storage inventories. Nevertheless, NYMEX prices remained remarkably high throughout 2004. In fact these prices only settled below $5.00/Mmbtu for a brief time in September. The NYMEX market was supported by our industry's inability to increase the U.S. domestic natural gas supply, in addition to a surging crude oil market, and a series of damaging hurricanes.

The last few years, the industry has relied on using spare gas production capacity during the coldest weather to offset storage withdrawal concerns. However, the current environment is decidedly different as natural gas production now runs at capacity all year long. This changing paradigm can be regarded as the principal reason that natural gas prices have remained at lofty levels in spite of gas storage inventories being historically high, and the expectation for storage to remain on the upper end of the profile.

Supply: Concerns over both near-term and long-term supplies of natural gas and oil have fueled an extended period of strong fundamentals in the energy markets.

Demand: Even though demand has grown over the past few years and is expected to continue to expand, it remains sensitive to sudden price moves.

While natural gas prices have reached unprecedented levels, crude oil's strength and volatility also set records through 2004. Although the two commodities trade on somewhat different fundamentals, the overall bullish sentiment of crude oil influenced the natural gas market. With legitimate concerns over the domestic gas production situation, all it took was a series of hurricanes to upset the market picture and solidify the market's concern over production growth rates.

Essentially U.S. domestic natural gas production has not grown over the last five years and has lethargic production growth forecasts for 2005. The average gas rig count of 1024 during 2004 (17 percent higher than 2003) is not expected to increase measurably due to the current maximization of available equipment and personnel. As the industry experiences steeper decline rates and a limited inventory of large drilling prospects, the prognoses in the short term will lead to continued concern for U.S. production.

The development of increased LNG imports has been a topic of consideration to cope with supply. While current LNG imports make up roughly three percent of the U.S. supply base, future LNG projects may double that rate during the next five years, adding an incremental level of production. However, this small addition to the supply picture does not in itself offer much support to the pricing environment.

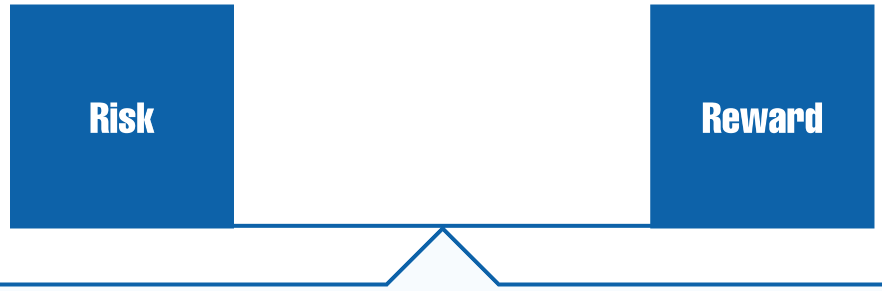
All in all, oil and gas market fundamentals are poised to support higher commodity prices and a higher level of activity throughout the industry for 2005 and beyond. To that end, we will continue to utilize a representative price deck to budget and plan for our 2005 program and financial results.

As the industry becomes more stable on the global issues and more predictable on domestic issues, we are expecting a less volatile price environment during 2005 and into the future, adding more consistent results for the company. We will also continue to evaluate both domestic and global issues affecting our business and will take steps necessary to mitigate the volatility during 2005 and into the future, where appropriate.

Left: Terry Jackson, Senior Drilling and Completion Engineer on location in Wyoming.

Risk: Managing the commensurate risk in the investment program is extremely important to value creation. Cabot is fortunate to have a wide range of projects along the risk spectrum.

Reward: An acceptable reward relative to risk requires extensive basin knowledge and a constant review of results.



In conjunction with our balanced strategic focus, we continued to foster discipline this year in our business model. Specific initiatives undertaken included a stock buyback program, extension of our revolving debt arrangement (to five years), alignment of our stock compensation program with shareholders, initiative to improve funding status of our pension plan and compliance work for Sarbanes-Oxley.

Probably the most profound decision for the Company was to re-commence a share buyback program. The Company entered 2004 with no debt outstanding on its Revolving Credit Facility and a budget that would generate free cash flow for the third consecutive year. The initial focus for our excess cash flow was to search for complimentary assets in the M&A arena that could add value to Cabot. However, with the robust nature of the forward price curve, easy access to capital and lack of drilling inventory by some companies, the acquisition market heated up and became very competitive. Our efforts were not fruitful here. During 2004, Cabot evaluated more than 70 different opportunities, consummating only two small acquisitions in its East Region.

Part of our analysis was the comparative valuation of purchasing outside reserves versus buying Cabot's reserves on the stock exchange. At a time when many reserves were being purchased for over $2.00 per Mcfe; based on our stock value, we traded between $1.10 and $1.45 per Mcfe. This analysis led management to initiate a buyback program that netted 405,100 shares during the year at an average price of $38.58 per share, resulting in the best return with minimal risk. The Company has budgeted a portion of its free cash flow to repurchase additional shares of stock during 2005.

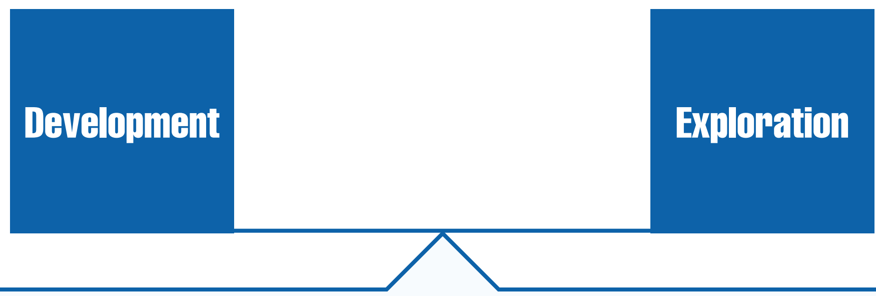
In conjuction with the fundamentals in the energy market, capital was readily available to the sector in 2004. Cabot took advantage of this environment and extended its $250 million credit facility five years (maturing now in 2009), while at the same time improving the underlying pricing. At year-end there were no outstanding balances on this facility. This credit arrangement affords us significant flexibility should we find that value added deal.

During 2004, the Compensation Committee acted on a recommendation from management, and modified the long-term incentive awards to a combination of restricted stock (for retention purposes) and performance shares which are tied to total shareholder return versus a peer group. The performance shares took the place of stock options, provided a stock award parallel to the shareholder's interests, and was less dilutive (due to fewer number of shares awarded).

Cabot Oil & Gas inherited a level of legacy costs, which we continue to manage. In 2004, the Company determined that it could use its current year funding to cash out individual deferred vested pension balances of less than $50,000 (i.e. those individuals who are vested in the plan but for one reason or another elected to leave the Company before retirement). The program, which was completely optional, was successful in cashing out 140 individuals from the plan.

Corral Creek drilling activity in Wyoming.

Probably the most significant task of the year was the required compliance under Sarbanes-Oxley Section 404 regulations, which relates to management's assessment of the effectiveness of Cabot's control system. While the undertaking was extensive, the results reinforced our focus on detail and accuracy. Very minor adjustments were made to our processes as a result of the evaluation. The one outcome experienced by all registrants is the high external cost of this project which for Cabot totaled $2.4 million, before valuing internal personnel time.



As we discussed briefly in the shareholders' letter, one of our 2005 priorities is to focus on growing our production profile. In 2004, the Company continued to allocate capital toward long-lived reserve basins and share repurchases which was consistent with budgeted expectations. Unfortunately, some well performance issues and hurricane related shut-ins caused us to fall somewhat short of our production expectation.

How do we improve these results? We remain focused on long-term value creation and plan to utilize our financial flexibility to secure near-term opportunities. We firmly believe that with the acreage positions we have built over the last several years throughout our regions, we have the opportunity to increase reserves at a value added cost, and to enhance our production rates.

Our focus is on balancing our investment between development drilling (i.e. commodity type plays) and exploration drilling. Exploration efforts in basin-centered gas plays can set up repeatable, low-risk development locations (as is the case in the Rocky Mountains and north Louisiana). This contrasts with the typical Gulf Coast wildcat prospect that produces at high rates, but usually has only a few, if any, offsets.

For 2004 our commodity play in the East delivered a 100 percent successful development program of 168 net wells that added 80 Bcfe of reserves at less than $.80 per Mcfe and grew production five percent year-over-year. Based on this success, our continued investment in infrastructure in the region and a vast inventory of locations, we will increase our program to 200 wells for 2005. We have a multi-year drilling inventory at that program level.

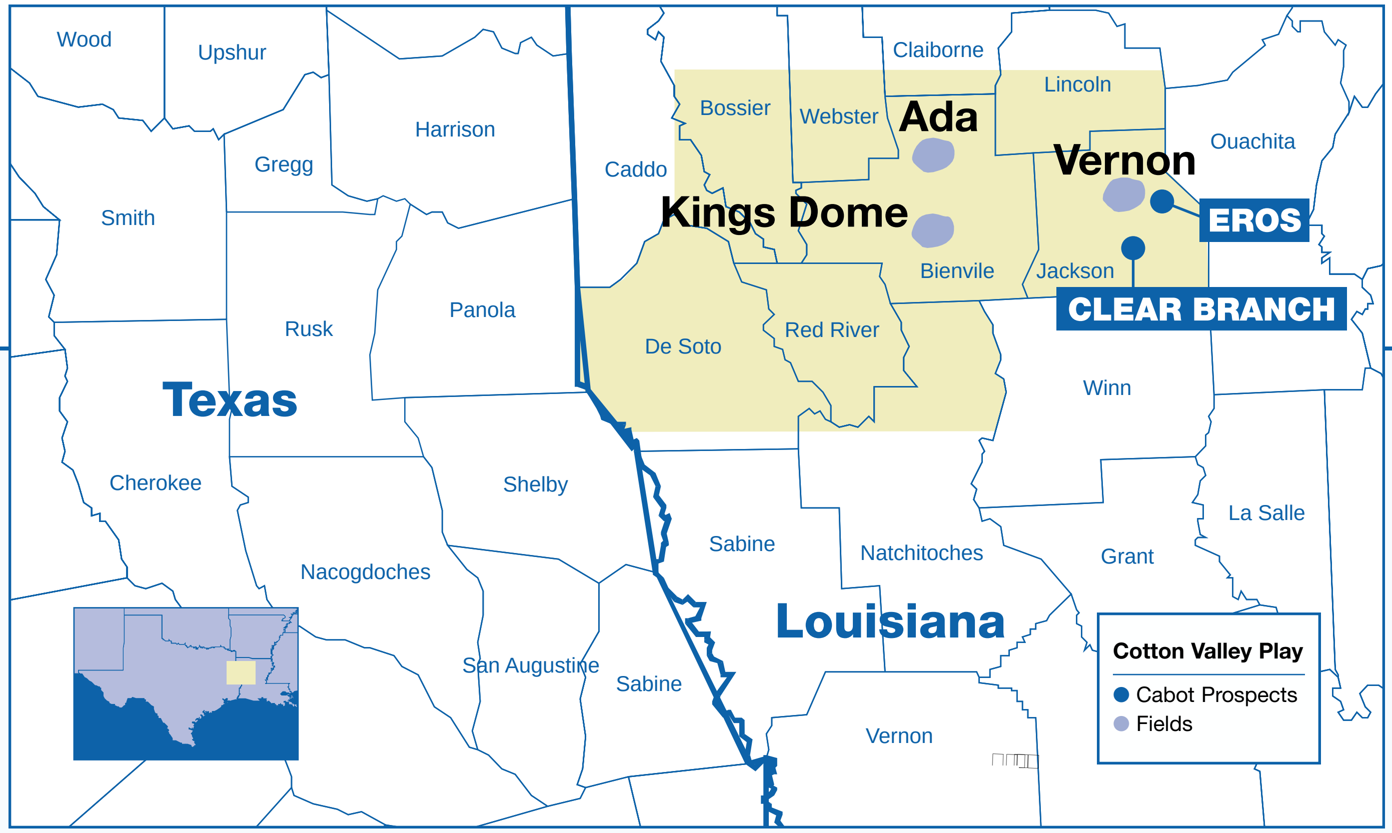
In terms of basin-centered gas activity two projects moved forward in 2004. Wind Dancer, in the Green River basin of Wyoming, added six wells and has nine producing wells in the play at the end of 2004. We have about 25 locations remaining in this field on 160 acre spacing. Drilling will continue in 2005 within the government mandated drilling window of July to December.

Corral Creek, in the Bighorn basin, was a 2004 discovery that has seen two delineation wells drilled to appraise the extent of the field. Of these wells one was successful. Based on this new data, the Company will continue drilling here in 2005. With continued success multiple locations remain to be drilled on Cabot's 19,000 acres.

As an example of the value in Cabot's portfolio, a significant impact opportunity has commenced in our north Louisiana Cotton Valley play. Cabot holds over 35,000 acres in this area with six different prospects. The initial well will evaluate the Cotton Valley prospect at Clear Branch (see map), which consists of 20,000 acres that is located slightly southeast of Anadarko's Vernon field (a disclosed TCF accumulation). We have two wells planned for this area in 2005 and with success, have staked an

Development: With its legacy assets, new technology and exploration success, Cabot has amassed an extensive level of low-risk drilling opportunities throughout the Company.

Exploration: Each year about 30 percent of our capital program is geared toward growth opportunities in search of new reserves.



additional six locations, which could be quickly exploited. In addition, we have three wells planned for Eros (see map) which could also have a long lasting positive impact on Cabot. Results of our initial drilling should be known soon after this writing goes to press.

From the wildcat perspective for 2004, the Company was successful on 15 out of 20 attempts, including seven of 11 in the Gulf Coast. Exploration highlights of the year included two wells at Little Horn Bayou, Eugene Island 280, Single Eagle and Big Indian prospects in the Paradox Basin. For 2005 the exploration effort will total 32 wells out of a total anticipated well count of about 300.

Projects of note include initial wildcats on our Cotton Valley acreage in north Louisiana, two wildcats in the East, which will extend our traditional development plays, one wildcat in the West, which will continue our exploration program in the Paradox basin, five wildcats in Canada looking for Slave Point dolomite reservoirs and deep basin tight sand accumulations, along with an offshore deep shelf test with a major exploration and production company.

Our goal remains to grow our stable foundation of assets through extensive development drilling, complimented by an exploration effort that in some instances also adds to the development inventory. The planned result over time will be a production profile that is dominated by long life well production and lower decline rates with less volatility creating the opportunity to grow both reserves and production with a portion of our generated cash flow.

Board of Directors

Committees

Audit Committee
John G. L. Cabot - *Chairman*
Robert F. Bailey
Robert Kelley
P. Dexter Peacock

Compensation Committee
William P. Vititoe - *Chairman*
John G. L. Cabot
James G. Floyd
Robert Kelley

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

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

Safety and Environmental Affairs Committee
Robert F. Bailey - *Chairman*
James G. Floyd
William P. Vititoe

Directors

Dan O. Dinges
Chairman, President and Chief Executive Officer

Robert F. Bailey
R.F. Bailey Investments (acquisitions and asset management)
B&J Exodus, Ltd (private investment partnership)
Former President and Chief Executive Officer, TransRepublic Resources, Inc.

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

James G. Floyd
JGF Inc. (private investments)
Former President, Chief Executive Officer and Director, Houston Exploration Company

Robert Kelley
Kellco Investments (private investment company)
Former Chairman of the Board, President and Chief Executive Officer, Noble Affiliates, Inc. (Subsequently renamed Noble Energy Inc.)

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

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

William P. Vititoe
Former Chairman of the Board, Chief Executive Officer and President, Washington Energy Company

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended **December 31, 2004**
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 June 30, 2004), the last business day of registrant's most recently completed second fiscal quarter was approximately $1.4 billion.

As of January 31, 2005, there were 32,414,760 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held April 28, 2005 are incorporated by reference into Part III of this report.

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

Part I

ITEM 1. Business

OVERVIEW

Cabot Oil & Gas is an independent oil and gas company engaged in the exploration, development, acquisition and exploitation of oil and gas properties located in North America. The five principal areas of operation are Appalachian Basin, Rocky Mountains, Anadarko Basin, onshore and offshore the Texas and Louisiana Gulf Coast, and the gas basin of West Canada. Operationally, we have four regional offices located in the East region, the West region, which is comprised of the Rocky Mountains and Mid-Continent areas, the Gulf Coast region and Canada.

In 2004, energy commodity prices remained strong throughout the year. This strong price environment allowed us to pursue our largest organic capital program ever while still maintaining our financial flexibility. This flexibility should provide us the ability to take advantage of attractive acquisition opportunities that may arise. At December 31, 2004, our debt to total capital ratio was 37%, down from 43% at the end of 2003. Natural gas production increased to 72.8 Bcf in 2004 from 71.9 Bcf in 2003. This growth was directly related to our 2003 drilling program which focused on natural gas projects. On an equivalent basis, our production level in 2004 was down slightly from 2003. We produced 84.8 Bcfe, or 232.3 Mmcfe per day, this year, as compared to 89.0 Bcfe, or 243.8 Mmcfe per day, in 2003. The growth in natural gas production was offset by the loss of production associated with the late 2003 sale of non-strategic properties and natural decline in oil production in south Louisiana. Our 2004 realized natural gas price was $5.20 per Mcf, compared to a 2003 price of $4.51. Our realized crude oil price was $31.55 per Bbl, compared to a 2003 price of $29.55. Our average hedged prices on natural gas and crude oil for 2005 anticipated production are expected to be higher than comparable prices realized from hedging in 2004. To lock in prices above historical levels for a portion of our production as a result of the strong commodity prices, we layered in oil and gas hedge instruments throughout 2004 to cover production in 2004 and 2005. At December 31, 2004, 44% and 25% of our natural gas and crude oil anticipated production, respectively, are hedged for 2005 through the use of derivatives that qualify for hedge accounting. Including our range swaps, which do not qualify for hedge accounting, 75% of our crude oil production is hedged for 2005. No derivatives are in place for 2006. Our decision to hedge 2005 production fits with our risk management strategy and allows the Company to lock in the benefit of high commodity prices on a portion of our anticipated production.

Net income of $88.4 million or $2.72 per share exceeded last year by $67.2 million or $2.06 per share. The year over year net income increase was achieved due to higher natural gas revenues from higher commodity prices. Operating Revenues increased by $21.0 million or 4% due to strong commodity prices. Natural gas production revenues increased by $57.1 million over the prior year; this increase was partially offset by a decrease in crude oil and condensate revenues of $21.0 million and a decrease in brokered natural gas revenues of $11.4 million. In addition, operating expenses decreased between 2004 and 2003 as a result of the 2003 non-cash pre-tax impairment charge of $93.8 million. Also contributing to the decrease were lower brokered natural gas cost and lower exploration expense. Net income in 2003 was also reduced by a $6.8 million cumulative effect of accounting change related to SFAS 143.

For the year ended December 31, 2004, we drilled 256 gross wells with a success rate of 95% compared to 173 gross wells with a success rate of 89% for the comparable period of the prior year. Our 2004 capital and exploration spending was $259.5 million compared to $188.2 million in 2003. We concentrated our 2004 capital spending program on projects balancing acceptable risk with the strongest economics. In the past, we have used a portion of the cash flow from our long-lived East and Mid-Continent natural gas reserves to fund our exploration and development efforts in the Gulf Coast and Rocky Mountain areas. In 2004, we continued that practice to a lesser extent as we increased our capital expenditures in the East in response to the success of the 2003 drilling program. The main recipient of these dollars was Canada where we commenced our drilling program with a $16.2 million investment. In 2005, we plan to spend approximately $280 million which includes a layer of investment for new projects or property acquisitions that may arise during 2005.

Our proved reserves totaled approximately 1,202 Bcfe at December 31, 2004, of which 94% was natural gas. This reserve level was up slightly from 1,142 Bcfe at December 31, 2003 on the strength of results from our drilling program and the lack of reserve sales during the year.

The following table presents certain information as of December 31, 2004.

	East	West: Rocky Mountains	West: Mid-Continent	West: Total West	Gulf Coast	Canada	Total
Proved Reserves at Year End *(Bcfe)*							
Developed	398.9	187.4	167.6	355.0	149.4	6.4	909.7
Undeveloped	151.6	50.2	21.7	71.9	67.7	1.5	292.7
Total	**550.5**	**237.6**	**189.3**	**426.9**	**217.1**	**7.9**	**1,202.4**
Average Daily Production *(Mmcfe per day)*	53.6	35.9	26.5	62.4	115.3	1.0	232.3
Reserve Life Index *(In years)* (1)	28.1	18.1	19.5	18.7	5.1	N/A	14.1
Gross Wells	2,584	533	650	1,183	751	14	4,532
Net Wells (2)	2,393.3	242.6	452.9	695.5	495.4	1.5	3,585.7
Percent Wells Operated *(Gross)*	96.6%	52.9%	78.2%	66.8%	74.3%	21.4%	84.9%

(1) *Reserve Life Index is equal to year-end reserves divided by annual production. Canada is not calculated since initial production commenced in mid-2004. Canada has also been excluded from the Total for purposes of the reserve life index calculation.*

(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.*

East Region

Our East activities are concentrated in West Virginia, and to a lesser extent in New York. In this region, our assets include a large undeveloped acreage position, a high concentration of wells, natural gas gathering and pipeline systems, and storage capacity. Capital and exploration expenditures were $75.2 million for 2004, or 29% of our total 2004 capital spending, and $40.6 million for 2003. For 2005, we have budgeted $75.3 million for capital and exploration expenditures in the region.

At December 31, 2004, we had 2,584 wells (2,393.3 net), of which 2,497 wells are operated by us. There are multiple producing intervals that include the Big Lime, Weir, Berea, Devonian Shale and Oriskany formations at depths primarily ranging from 1,000 to 9,500 feet. Average net daily production in 2004 was 53.6 Mmcfe. While natural gas production volumes from East reservoirs are relatively low on a per-well basis compared to other areas of the United States, the productive life of East reserves is relatively long. At December 31, 2004, we had 550.5 Bcfe of proved reserves (substantially all natural gas) in the East region, constituting 46% of our total proved reserves. This region is managed from our office in Charleston, West Virginia.

In 2004, we drilled 171 wells (167.5 net) in the East region, of which 166 wells (163 net) were development and extension wells. In 2005, we plan to drill approximately 200 wells.

In 2004, we produced and marketed approximately 80 barrels of crude oil/condensate per day in the East region at market responsive prices.

Ancillary to our exploration, development and production operations, we operate a number of gas gathering and transmission pipeline systems with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2004. 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 increase for shorter intervals of time 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 East region. The pipeline systems and storage fields are fully integrated with our operations.

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

Approximately 65% of our natural gas sales volume in the East region is sold at index-based prices under contracts with a term of one year or greater. In addition, spot market sales are made under month-to-month contracts, while industrial and utility sales generally are made under year-to-year contracts. Approximately 2% of East production is sold on fixed price contracts that typically renew annually.

West Region

Our activities in the West region are managed by a regional office in Denver. At December 31, 2004, we had 426.9 Bcfe of proved reserves (96% natural gas) in the West region, constituting 36% of our total proved reserves.

Rocky Mountains

Our Rocky Mountains activities are concentrated in the Green River, Wind River and Big Horn Basins in Wyoming and Paradox Basin in Colorado. At December 31, 2004, we had 237.6 Bcfe of proved reserves (95% natural gas) in the Rocky Mountain area, 20% of our total proved reserves. Capital and exploration expenditures in the Rocky Mountains were $41.5 million for 2004, or 16% of our total capital and exploration expenditures, and $22.3 million for 2003. Spending for 2004 included $30.5 million for drilling activity and $7.5 million of dry hole expense and geophysical and geological procedures. For 2005, we have budgeted $33.6 million for capital and exploration expenditures in the area.

We had 533 wells (242.6 net) in the Rocky Mountains area as of December 31, 2004, of which 282 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 5,500 to 15,000 feet. Average net daily production in the Rocky Mountains during 2004 was 35.9 Mmcfe.

In 2004, we drilled 29 wells (14.3 net) in the Rocky Mountains, of which 26 wells (13.0 net) were development wells. In 2005, we plan to drill 30 wells.

Mid-Continent

Our Mid-Continent activities are concentrated in the Anadarko Basin in southwest Kansas, Oklahoma and the panhandle of Texas. Capital and exploration expenditures were $12.1 million for 2004, or 5% of our total 2004 capital and exploration expenditures, and $11.2 million for 2003. For 2005, we have budgeted $8.5 million for capital and exploration expenditures in the area.

As of December 31, 2004, we had 650 wells (452.9 net) in the Mid-Continent area, of which 508 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 2,200 to 10,000 feet. Average net daily production in 2004 was 26.5 Mmcfe. At December 31, 2004, we had 189.3 Bcfe of proved reserves (97% natural gas) in the Mid-Continent area, 16% of our total proved reserves.

In 2004, we drilled 21 wells (18.9 net) in the Mid-Continent, all of which were development and extension wells. In 2005, we plan to drill 11 wells.

Our principal markets for West region natural gas are in the northwest and midwest United States. We sell natural gas to power generators, natural gas processors, local distribution companies, industrial customers and marketing companies. Currently, approximately 75% of our natural gas production in the West region is sold primarily under contracts with a term of one to three years at index-based prices. Another 23% of the natural gas production is sold under short-term arrangements at index-based prices and the remaining 2% is sold under certain fixed-price contracts. The West region properties are connected to the majority of the midwest and northwest interstate and intrastate pipelines, affording us access to multiple markets.

In 2004, we produced and marketed approximately 450 barrels of crude oil/condensate per day in the West region at market responsive prices.

Gulf Coast Region

Our exploration, development and production activities in the Gulf Coast region are primarily concentrated in north and south Louisiana, south Texas and the Gulf of Mexico. A regional office in Houston manages the operations. Principal producing intervals are in the Cotton Valley, Hosston, Miocene and Frio age formations in Louisiana and the Frio, Vicksburg and Wilcox formations in Texas at depths ranging from 3,000 to 25,000 feet. Capital and exploration expenditures were $112.6 million for 2004, or 43% of our total capital and exploration expenditures, and $111.6 million for 2003. For 2005, we have budgeted $105.0 million of our total budget for capital and exploration expenditures in the region. Our 2005 Gulf Coast drilling program will continue to emphasize impact exploration opportunities both on and offshore, augmented by development activity in our focus areas of south Texas and throughout coastal Louisiana.

In 2004, we drilled 31 wells (17.6 net) in the Gulf Coast region, of which 20 wells (12.4 net) were development wells. In 2005 we plan to drill 42 wells. We had 751 wells (495.4 net) in the Gulf Coast region as of December 31, 2004, of which 558 wells are operated by us. Average daily production in 2004 was 115.3 Mmcfe, compared to 124.1 Mmcfe in 2003. The decline is the result of lower production from our properties in south Louisiana, offset partially by increased production from the coastal Texas area. At December 31, 2004, we had 217.1 Bcfe of proved reserves (78% natural gas) in the Gulf Coast region, which represented 18% of our total proved reserves.

Our principal markets for Gulf Coast region natural gas are in the industrialized Gulf Coast area and the northeast United States. We sell natural gas to intrastate pipelines, natural gas processors and marketing companies. Currently, approximately 40% 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 60% of our sales volumes are sold at index-based prices under short-term agreements. The Gulf Coast properties are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

In 2004, we produced and marketed approximately 5,000 barrels of crude oil/condensate per day in the Gulf Coast region at market responsive prices.

Canada Region

Our activities in the Canada region are managed by a regional office in Calgary, Alberta. Our Canadian exploration, development and producing activities are concentrated in the Provinces of Alberta and British Columbia. At December 31, 2004, we had 7.9 Bcfe of proved reserves (91% natural gas) in the Canada region, constituting less than 1% of our total proved reserves.

Capital and exploration expenditures in Canada were $16.2 million for 2004, or 6% of our total capital and exploration expenditures, and $0.8 million for 2003. For 2005, we have budgeted $16.0 million for capital and exploration expenditures in the area.

We had 14 wells (1.5 net) in the Canada region as of December 31, 2004, of which 3 wells are operated by us. Principal producing intervals in the Canada region are in the Falher, Bluesky, Cadomin and the Swan Hills formations at depths ranging from 9,500 to 16,000 feet. Average net daily production in Canada during 2004 was 1.0 Mmcfe.

In 2004, we drilled 4 wells (1.5 net) in Canada, of which 3 wells (1.1 net) were development and extension wells. In 2005, we plan to drill 10 wells.

In 2004, we produced and marketed approximately 10 barrels of crude oil/condensate per day in the Canada region at market responsive prices.

RISK MANAGEMENT

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production in all of our regions. While there are many different types of derivatives available, in 2004 we primarily employed natural gas and oil price swap and collar agreements to attempt to manage price risk more effectively. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas or crude oil for the period is greater or less than the fixed price established for that period when the swap is put in place. The collar arrangements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor.

We will continue to evaluate the benefit of employing derivatives in the future. Please read Management's Discussion and Analysis of Financial Condition and Results of Operations – Commodity Price Swaps and Options for further discussion concerning our use of derivatives.

RESERVES

Current Reserves

The following table presents our estimated proved reserves at December 31, 2004.

	Natural Gas *(Mmcf)*			**Liquids** [1] *(Mbbl)*			**Total** [2] *(Mmcfe)*		
	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	Total
East	396,521	151,184	547,705	401	53	454	398,927	151,500	550,427
Rocky Mountains	177,454	47,911	225,365	1,657	384	2,041	187,395	50,216	237,611
Mid-Continent	162,625	21,491	184,116	831	39	870	167,609	21,728	189,337
Gulf Coast	115,528	54,216	169,744	5,648	2,240	7,888	149,417	67,653	217,070
Canada	5,706	1,445	7,151	115	16	131	6,399	1,539	7,938
Total	**857,834**	**276,247**	**1,134,081**	**8,652**	**2,732**	**11,384**	**909,747**	**292,636**	**1,202,383**

(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. Miller and Lents concluded the following: In their judgment 1) we have an effective system for gathering data and documenting information required to estimate our proved reserves and project our future revenues, 2) we used appropriate engineering, geologic and evaluation principles in making our estimates and projections and 3) our total proved reserves are reasonable. 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 2004.

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

Historical Reserves

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

	Natural Gas *(Mmcf)*	Oil & Liquids *(Mbbl)*	Total *(Mmcfe)*[1]
December 31, 2001	**1,036,004**	**19,684**	**1,154,109**
Revision of Prior Estimates	14,405	1,871	25,631
Extensions, Discoveries and Other Additions	64,945	851	70,053
Production	(73,670)	(2,909)	(91,126)
Purchases of Reserves in Place	26,262	261	27,828
Sales of Reserves in Place	(6,987)	(1,365)	(15,179)
December 31, 2002	**1,060,959**	**18,393**	**1,171,316**
Revision of Prior Estimates	(6,122)	307	(4,278)
Extensions, Discoveries and Other Additions	105,497	1,723	115,835
Production	(71,906)	(2,846)	(88,976)
Purchases of Reserves in Place	1,590	—	1,591
Sales of Reserves in Place	(20,534)	(5,474)	(53,380)
December 31, 2003	**1,069,484**	**12,103**	**1,142,108**
Revision of Prior Estimates	(7,850)	185	(6,739)
Extensions, Discoveries and Other Additions	140,986	1,074	147,426
Production	(72,833)	(2,002)	(84,847)
Purchases of Reserves in Place	5,384	24	5,525
Sales of Reserves in Place	(1,090)	—	(1,090)
December 31, 2004	**1,134,081**	**11,384**	**1,202,383**
Proved Developed Reserves			
December 31, 2001	804,646	15,328	896,612
December 31, 2002	819,412	13,267	899,016
December 31, 2003	812,280	9,405	868,712
December 31, 2004	**857,834**	**8,652**	**909,747**

[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,		
	2004	2003	2002
Net Wellhead Sales Volume			
Natural Gas *(Bcf)*			
Gulf Coast	**31.3**	30.0	30.4
West	**21.9**	23.8	25.3
East	**19.4**	18.6	18.0
Canada	**0.2**	—	—
Crude/Condensate/Ngl *(Mbbl)*			
Gulf Coast	**1,809**	2,625	2,655
West	**163**	193	221
East	**27**	27	33
Canada	**3**	—	—
Produced Natural Gas Sales Price *($/Mcf)*[1]			
Gulf Coast	**$ 5.27**	$ 4.78	$ 3.34
West	**4.75**	3.67	2.39
East	**5.60**	5.15	3.38
Canada	**4.69**	—	—
Weighted Average	**5.20**	4.51	3.02
Crude/Condensate Sales Price *($/Bbl)*[1]	**$ 31.55**	$ 29.55	$ 23.79
Production Costs *($/Mcfe)*[2]	**$ 0.99**	$ 0.87	$ 0.70

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

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

Leasehold Acreage

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
State						
Arkansas	1,981	425	0	0	1,981	425
Colorado	16,389	14,089	170,704	91,115	187,093	105,204
Kansas	29,067	27,745	0	0	29,067	27,745
Louisiana	49,541	39,784	47,366	45,235	96,907	85,019
Montana	397	210	32,828	25,648	33,225	25,858
New York	2,956	1,105	11,326	6,405	14,282	7,510
North Dakota	0	0	870	96	870	96
Ohio	6,259	2,422	1,613	428	7,872	2,850
Oklahoma	167,679	117,118	13,698	9,059	181,377	126,177
Pennsylvania	111,953	63,752	3,449	2,312	115,402	66,064
Texas	107,754	74,051	66,149	48,130	173,903	122,181
Utah	1,740	529	164,404	86,370	166,144	86,899
Virginia	22,195	20,072	5,766	4,196	27,961	24,268
West Virginia	576,944	544,737	162,033	146,605	738,977	691,342
Wyoming	142,816	72,340	370,869	226,132	513,685	298,472
Federal Offshore	10,933	2,218	120,244	88,673	131,177	90,891
Total	**1,248,604**	**980,597**	**1,171,319**	**780,404**	**2,419,923**	**1,761,001**

Mineral Fee Acreage

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
State						
Colorado	0	0	2,899	271	2,899	271
Kansas	160	128	0	0	160	128
Louisiana	628	276	0	0	628	276
Montana	0	0	589	75	589	75
New York	0	0	6,545	1,353	6,545	1,353
Oklahoma	16,580	13,979	730	179	17,310	14,158
Pennsylvania	524	524	1,573	502	2,097	1,026
Texas	327	177	754	327	1,081	504
Virginia	17,817	17,817	100	34	17,917	17,851
West Virginia	97,455	79,093	51,447	49,593	148,902	128,686
Total	**133,491**	**111,994**	**64,637**	**52,334**	**198,128**	**164,328**
Aggregate Total	**1,382,095**	**1,092,591**	**1,235,956**	**832,738**	**2,618,051**	**1,925,329**

Canada Leasehold Acreage

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Province						
Alberta	2,560	621	4,489	1,407	7,049	2,028
British Columbia	0	0	7,778	3,889	7,778	3,889
Total	**2,560**	**621**	**12,267**	**5,296**	**14,827**	**5,917**

Total Net Acreage by Region of Operation

	Developed	Undeveloped	Total
Gulf Coast	89,741	181,911	271,652
West	273,328	439,399	712,727
East	729,522	211,428	940,950
Canada	621	5,296	5,917
Total	**1,093,212**	**838,034**	**1,931,246**

Total Net Undeveloped Acreage Expiration by Region of Operation

The following table presents our net undeveloped acreage expiring over the next three years by operating region as of December 31, 2004. The figures below assume no future successful development or renewal of undeveloped acreage.

	2005	2006	2007
Gulf Coast	6,257	11,328	48,513
West	75,595	42,591	34,395
East	9,345	15,491	64,756
Total	**91,197**	**69,410**	**147,664**

Well Summary

The following table presents our ownership at December 31, 2004, in natural gas and oil wells in the Gulf Coast region (consisting primarily of various fields located in Louisiana and Texas), in the West region (consisting of various fields located in Oklahoma, Kansas, Colorado and Wyoming), in the East region (consisting of various fields located in West Virginia, Virginia and Ohio) and in the Canada region (consisting of various fields located in the Provinces of Alberta and British Columbia). This summary includes natural gas and oil wells in which we have a working interest.

	Natural Gas		Oil		Total [1]	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	584	353.7	167	141.7	751	495.4
West	1,127	663.1	56	32.4	1,183	695.5
East	2,559	2,381.2	25	12.1	2,584	2,393.3
Canada	14	1.5	0	0	14	1.5
Total	**4,284**	**3,399.5**	**248**	**186.2**	**4,532**	**3,585.7**

[1] *Total does not include service wells of 74 (64.5 net).*

Drilling Activity

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

	Year Ended December 31, 2004									
	Gulf Coast		West		East		Canada		**Total**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	**Gross**	**Net**
Development Wells										
Successful	16	9.5	45	30.8	164	161.0	2	0.6	**227**	**201.9**
Dry	4	2.9	1	0.6	1	1.0	0	0.0	**6**	**4.5**
Extension Wells										
Successful	0	0.0	0	0.0	1	1.0	1	0.5	**2**	**1.5**
Dry	0	0.0	1	0.5	0	0.0	0	0.0	**1**	**0.5**
Exploratory Wells										
Successful	7	2.9	3	1.3	4	4.0	1	0.4	**15**	**8.6**
Dry	4	2.3	0	0.0	1	0.5	0	0.0	**5**	**2.8**
Total	**31**	**17.6**	**50**	**33.2**	**171**	**167.5**	**4**	**1.5**	**256**	**219.8**
Wells Acquired [1]	0	0.0	2	1.9	25	25.0	0	0.0	**27**	**26.9**
Wells in Progress at End of Year	2	1.0	12	6.4	0	0.0	2	0.6	**16**	**8.0**

[1] *Includes the acquisition of net interest in wells in which we already held an ownership interest.*

Competition

Competition in our primary producing areas is intense. Price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery records, affect competition. We believe that our extensive acreage position, existing natural gas gathering and pipeline systems and storage fields enhance our competitive position over other producers in the East region who do not have similar systems or facilities in place. We also believe that our competitive position in the East 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 West and Gulf Coast regions and Canada.

OTHER BUSINESS MATTERS

Major Customer

In 2004, approximately 11% of our total sales were made to one customer. In 2003 and 2002, approximately 11% and 14%, respectively, of our total sales were made to one customer. In 2002, this customer operated certain properties in which we have interests in the Gulf Coast and purchased all of the production from these wells. This customer would resell the natural gas and oil to third parties with whom we would deal directly if the customer either ceased to exist or stopped buying our portion of the production.

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 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 generally 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 definition covers 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, and by increasing the transparency of pricing for pipeline services. 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 data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis.

In light of these statutory and regulatory changes, most pipelines have divested their gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants, and most pipelines have also implemented the large-scale divestiture of their gas gathering facilities to affiliated or non-affiliated companies. Interstate pipelines thus now generally provide unbundled, open and nondiscriminatory transportation and transportation-related services to producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking such services. Sellers and buyers of gas have gained direct access to the particular pipeline services they need, and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace.

Certain of our pipeline systems and storage fields in West Virginia are regulated for safety compliance by the U.S. Department of Transportation (DOT) and the West Virginia Public Service Commission. In 2002, Congress enacted the Pipeline Safety Improvement Act of 2002, which contains a number of provisions intended to increase pipeline operating safety. The DOT's final regulations implementing the act became effective February 2004. Among other provisions, the regulations require that pipeline operators implement a pipeline integrity management program that must at a minimum include an inspection of gas transmission pipeline facilities within the next ten years, and at least every seven years thereafter.

We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. Similarly, it is impossible to predict what proposals, if any, that affect the oil and natural gas industry might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the recent trend toward federal deregulation 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 was completed in December 2000, where the FERC concluded that the rate index reasonably reflected actual pipeline costs. Upon judicial review, the pipeline transportation rates established under the index were increased slightly. The next review is scheduled in July 2005. Another FERC proceeding that may impact our transportation costs relates to an ongoing proceeding to determine whether and to what extent pipelines should be permitted to include in their transportation rates an allowance for income taxes attributable to non-corporate partnership interests. 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, or the ongoing review of the income tax allowance.

Environmental Regulations

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

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

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

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

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

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

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

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, 2004, Cabot Oil & Gas had 346 active employees. We recognize that our success is significantly influenced by the relationship we maintain with our employees. Overall, we believe that our relations with our employees are satisfactory. The Company and its employees are not represented by a collective bargaining agreement.

Website Access to Company Reports

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

Corporate Governance Matters

The Company's Corporate Governance Guidelines, Code of Business Conduct, Corporate Governance and Nominations Committee Charter, Compensation Committee Charter and Audit Committee Charter are available on the Company's website at www.cabotog.com, under the "Corporate Governance" section and a copy will be provided, without charge, to any shareholder upon request.

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 invested a higher percentage of our drilling dollars in the Gulf Coast, where insurance rates are significantly higher than in other regions such as the East. At December 31, 2004, we owned or operated approximately 3,300 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. While the outcome and impact on us cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our consolidated financial position. Operating results and cash flow, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Wyoming Royalty Litigation

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

In January 2002, 13 overriding royalty owners sued 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.

The federal district court judge certified two questions of state law for decision by the Wyoming State Supreme Court, which recently answered both questions. The Wyoming Supreme Court ruled that certain deductions taken by us from the plaintiffs were not proper and that the statutes of limitations advanced by us are discovery statutes and accordingly do not begin to run until the plaintiffs knew, or had reason to know, of the violation. We believe we have properly reported to the plaintiffs and, that if we did not, the plaintiffs knew or should have known the reporting was improper and the nature of the deductions, thus triggering the statutes of limitations. We still intend to raise defenses to the alleged failure to report claims. There is also a dispute as to how the interest should be calculated.

The federal judge refused to certify a question relating to the issue of the proper calculation of damages for failure to provide certain information required by statute on overriding royalty owner check stubs that had been decided adversely to our position in a state district court letter decision in a separate case. After the federal judge's refusal to certify this issue, the plaintiffs reduced the damages they were claiming. Based upon recent communication from the plaintiffs, they are now claiming $26.2 million in total damages which consists of $20.3 million for alleged violations of the check stub reporting statute and $5.9 million for all other damages.

In the opinion of our outside counsel, Brown, Drew & Massey, LLP, the likelihood of the plaintiffs recovering $20.3 million for the check stub reporting statute is remote. However, a reserve that management believes is adequate to provide for the check stub reporting statute and all other damages has been established based on management's estimate at this time of the probable outcome of this case.

West Virginia Royalty Litigation

In December 2001, we were sued by two royalty owners in West Virginia state court for an unspecified amount of damages. The plaintiffs have requested class certification under the West Virginia Rules of Civil Procedure and allege that we failed to pay royalty based upon the wholesale market value of the gas produced, that it had taken improper deductions from the royalty and failed to properly inform the plaintiffs and other similarly situated persons of deductions taken from the royalty. The plaintiffs have also claimed that they are entitled to a 1/8th royalty share of the gas sales contract settlement that we reached with Columbia Gas Transmission Corporation in the 1995 Columbia Gas Transmission Corporation bankruptcy proceeding.

Discovery and pleadings necessary to place the class certification issue before the state court have been ongoing. A hearing on the plaintiffs' motion for class certification was held on October 20, 2003, and proposed findings of fact and conclusions of law were submitted to the court on December 5, 2003. A status conference was held with the court and the court advised it intends to issue a ruling on the class certification motion. The court was expected to rule by December 2004, and we are still awaiting a decision. Discovery is proceeding on the claims pending the ruling on the class certification motion. Discovery is to be completed by April 1, 2005, and the trial is currently scheduled for August 15, 2005. If a class is certified it is expected this trial date will be continued to a later date.

The investigation into this claim continues and it is in the discovery phase. We are vigorously defending the case. We have a reserve that management believes is adequate based on its estimate at this time of the probable outcome of this case.

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. Plaintiffs filed their First Supplemental Original Petition on March 17, 2004 and their Second Supplemental Petition on November 12, 2004. The significant change in the second Supplemental Petition is that plaintiffs appear to limit their claim to the mineral estate, rather than making claims to both the surface and mineral estate. The plaintiffs allege that they are the rightful owners of a one-half undivided mineral interest in and to certain lands in Brooks County, Texas. As Cody Energy, LLC, we acquired certain leases and wells from Wynn-Crosby 1996, Ltd. in 1997 and 1998 and 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 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. The original trial date of May 19, 2003 was cancelled and a new trial date has not been set. We have not had the opportunity to conduct discovery in this matter. We estimate that production revenue from this field since its predecessor, Cody Energy, LLC, acquired title and since we acquired its lease is approximately $14.9 million. The carrying value of this property is approximately $34 million. Co-defendants Shell Oil Company and Shell Western E&P filed a motion for summary judgment seeking dismissal of plaintiffs' causes of action on multiple grounds. The original plaintiffs' attorneys asked permission from the Court to withdraw from the representation. The Court granted that request, and new attorneys for some, but not all of the plaintiffs have recently entered the case. The motion for summary judgment was reset and a hearing was held in December of 2003. We joined in the motion. After a second hearing, the Court denied the motion for summary judgment. The defendants have moved to add parties whose title interests are being challenged by the plaintiffs, and who are therefore necessary to the case, or in the alternative, abate the proceeding until the plaintiffs join all parties whose interests may be affected by plaintiffs' claims.

Although the investigation into this claim is in its early stages, we intend to vigorously defend the case. Should we receive an adverse ruling in this case, an impairment review would be assessed to ensure the carrying value of the property is recoverable. Management cannot currently determine the likelihood of an unfavorable outcome or range of any potential loss should the outcome be unfavorable. Accordingly, there has been no reserve established for this matter.

Raymondville Area

In April 2004, our wholly owned subsidiary, Cody Energy, LLC, filed suit in Willacy County, Texas against certain of our co-working interest owners in the Raymondville Area, located in Kenedy and Willacy Counties. In early 2003, Cody had proposed a new prospect to certain of these co-working interest owners located within jointly owned oil and gas leases. Some of the co-working interest owners elected to participate and some did not. The initial well was successful and subsequent wells have been drilled to exploit the discovery made in the first well.

In December 2003, certain of the co-working interest owners who elected not to participate in the initial well notified Cody that they believed that they had the right to participate in subsequent wells. Cody contends that, under the terms of the agreements between the parties, the co-working interest owners that elected not to participate in the initial well in the prospect were required to assign their interest in the proposed prospect to those who elected to participate. Alternatively, Cody contends that such owners lost their right to participate in subsequent wells within a 1,200 foot radius of the initial well.

The defendants have filed a counter claim against us and one of the defendants has filed a lien against Cody's interest in the leases in the Raymondville Area. Cody contends that this lien is improper and has sought damages for its filing. Cody is vigorously prosecuting this case which is in its early stage of discovery. No trial date has been set by the court.

Certain of the defendants filed a Motion for Partial Summary Judgment contending that they did not have adequate notice of the prospect proposal. Cody is contesting this Motion. In addition, in late December 2004, Cody filed a Motion for Final Summary Judgment asking the court to find that, under the terms of the agreements, Cody and the participating working interest owners are entitled to an assignment of the interests of the co-working interest owners who elected not to participate in the prospect. No hearing date has been set by the court.

Management cannot currently determine the likelihood of an unfavorable outcome or range of any potential loss should the outcome be unfavorable. Accordingly, there has been no reserve established for this matter.

Commitment and Contingency Reserves

We have established reserves for certain legal proceedings. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that we could incur approximately $11.1 million of additional loss with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

While the outcome and impact on us cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our consolidated financial position. Operating results and cash flow, however, could be significantly impacted in the reporting periods in which such matters are resolved.

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

No matters were submitted to a vote of security holders during the fourth quarter of 2004.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information about our executive officers as of February 18, 2005, 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	51	Chairman, President and Chief Executive Officer	2001
Michael B. Walen	56	Senior Vice President, Exploration and Production	1998
Scott C. Schroeder	42	Vice President and Chief Financial Officer	1997
J. Scott Arnold	51	Vice President, Land and Associate General Counsel	1998
R. Scott Butler	50	Vice President, Regional Manager, West Region	2001
Robert G. Drake	57	Vice President, Information Services and Operational Accounting	1998
Abraham D. Garza	58	Vice President, Human Resources	1998
Jeffrey W. Hutton	49	Vice President, Marketing	1995
Thomas S. Liberatore	48	Vice President, Regional Manager, East Region	2003
Lisa A. Machesney	49	Vice President, Managing Counsel and Corporate Secretary	1995
Henry C. Smyth	58	Vice President, Controller and Treasurer	1998

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

Dan O. Dinges joined Cabot Oil & Gas Corporation as President and Chief Operating Officer and as a member of the Board of Directors in September 2001. He was promoted to his current position of Chairman, President and Chief Executive Officer in May 2002. Mr. Dinges came to Cabot after a 20-year career with Samedan Oil Corporation, a subsidiary of Noble Affiliates, Inc. The last three years, Mr. Dinges served as Samedan's Senior Vice President, as well as Division General Manager for the Offshore Division, a position he held since August 1996. He also served as a member of the Executive Operating Committee for Samedan. Mr. Dinges started his career as a Landman for Mobil Oil Corporation covering Louisiana, Arkansas and the central Gulf of Mexico. After four years of expanding responsibilities at Mobil he joined Samedan as a Division Landman – Offshore. Over the years, Mr. Dinges held positions of increasing responsibility at Samedan including Division Manager, Vice President and ultimately Senior Vice President. Mr. Dinges received his BBA degree in Petroleum Land Management from The University of Texas.

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

Part II

ITEM 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

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
2004				
	First Quarter	**$ 32.90**	**$ 28.76**	**$ 0.04**
	Second Quarter	**42.30**	**30.13**	**0.04**
	Third Quarter	**45.08**	**38.80**	**0.04**
	Fourth Quarter	**48.38**	**40.90**	**0.04**
2003				
	First Quarter	$ 29.46	$ 24.40	$ 0.04
	Second Quarter	27.96	24.45	0.04
	Third Quarter	30.46	26.65	0.04
	Fourth Quarter	30.26	25.35	0.04

As of January 31, 2005, there were 693 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.

On February 28, 2005, the Company announced that the Board of Directors had declared a 3-for-2 split on the Company's Common Stock in the form of a stock distribution. The stock dividend will be distributed on March 31, 2005 to shareholders of record on March 18, 2005. In lieu of issuing fractional shares, the Company will pay cash based on the closing price of the Common stock on the record date.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

Issuer Purchases of Equity Securities [(1)]

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 2004	—	—	—	1,453,300
November 2004	136,000	$ 42.64	136,000	1,317,300
December 2004	25,000	$ 43.96	25,000	1,292,300
Total	**161,000**	$ 42.84		

[(1)] On August 13, 1998, the Company announced that its Board of Directors authorized the repurchase of two million shares of the Company's stock in the open market or in negotiated transactions. All purchases executed have been through open market transactions. There is no expiration date associated with the authorization to repurchase securities of the Company.

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)	**2004**	2003	2002	2001	2000
Statement of Operations					
Operating Revenues	**$ 530,408**	$ 509,391	$ 353,756	$ 447,042	$ 368,651
Impairment of Oil and Gas Properties [1]	**3,458**	93,796	2,720	6,852	9,143
Income from Operations	**160,653**	66,587	49,088	95,366	64,817
Net Income	**88,378**	21,132	16,103	47,084	29,221
Basic Earnings per Share	**$ 2.72**	$ 0.66	$ 0.51	$ 1.56	$ 1.07
Dividends per Common Share	**$ 0.16**	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Balance Sheet Data					
Properties and Equipment, Net	**$ 994,081**	$ 895,955	$ 971,754	$ 981,338	$ 623,174
Total Assets	**1,210,956**	1,055,056	1,100,947	1,092,810	776,353
Current Maturities of Long-Term Debt	**20,000**	—	—	—	16,000
Long-Term Debt	**250,000**	270,000	365,000	393,000	253,000
Stockholders' Equity	**455,662**	365,197	350,657	346,552	242,505

[1] *For discussion of impairment of oil and gas properties, refer to Note 2.*

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 42.

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

OVERVIEW

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

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

Our financial results depend upon many factors, particularly the price of natural gas and crude oil and our ability to market our production on economically attractive terms. Price volatility in the commodity markets has remained prevalent in the last few years. Throughout 2003 and 2004, the futures market reported unprecedented natural gas and crude oil contract prices. Our realized natural gas and crude oil price, net of the impact of derivative instruments, was $5.20 per Mcf and $31.55 per Bbl, respectively, in 2004. To ensure a certain rate of return for our program, we entered into a series of crude oil and natural gas price collars and swaps. These financial instruments are an integral element of our risk management strategy but prevented us from realizing the full impact of the price environment.

Commodity prices are impacted by many factors that are outside of our control. Historically, commodity prices have been volatile and we expect them to remain volatile. Commodity prices are affected by changes in market demands, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas and crude oil prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. In addition to production volumes and commodity prices, finding and developing sufficient amounts of crude oil and natural gas reserves at economical costs are critical to our long-term success.

The tables below illustrate how natural gas prices have fluctuated over the course of 2003 and 2004. "Index" represents the Henry Hub index price per Mmbtu. The "2003" and "2004" price is the natural gas price per Mcf realized by us and includes the realized impact of our natural gas price collar and swap arrangements, as applicable:

(In $ per Mcf)

Natural Gas Prices by Month - 2004

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	6.15	5.77	5.15	5.37	5.94	6.68	6.14	6.04	5.08	5.79	7.63	7.78
2004	**5.23**	**5.23**	**5.17**	**4.88**	**4.96**	**5.23**	**5.39**	**5.21**	**4.54**	**5.29**	**5.63**	**5.55**

(In $ per Mcf)

Natural Gas Prices by Month - 2003

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

Prices for crude oil have followed a similar path as the commodity price continued to maintain strength in 2003 and rose further in 2004. The tables below contain the NYMEX average crude oil price (Index) and our realized per barrel (Bbl) crude oil prices by month for 2003 and 2004. The "2003" and "2004" price is the crude oil price per Bbl realized by us and includes the realized impact of our crude oil derivative arrangements:

(In $ per Bbl)

Crude Oil Prices by Month - 2004

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	34.23	34.50	36.72	36.62	40.28	38.05	40.81	44.88	45.94	53.09	48.48	43.26
2004	**30.62**	**30.66**	**31.62**	**30.97**	**30.80**	**31.51**	**31.43**	**33.00**	**31.61**	**32.87**	**33.15**	**30.46**

(In $ per Bbl)

Crude Oil Prices by Month - 2003

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

We reported earnings of $2.72 per share, or $88.4 million, for 2004. This is up from the $0.66 per share, or $21.1 million, reported in 2003. The decline in impairments of oil and gas properties was the driving factor in this improvement. In 2003, there was an after-tax impairment of $54.4 million related to our Kurten field (see *Limited Partnership* for discussion of the impairment). In addition, the stronger price environment contributed to the earnings increase. Prices, including the impact of the hedge arrangements, rose 15% for natural gas and 7% for oil.

We drilled 256 gross wells with a success rate of 95% in 2004 compared to 173 gross wells with an 89% success rate in 2003. Total capital and exploration expenditures increased $71.3 million to $259.5 million in 2004 compared to $188.2 million for 2003. We believe our operating cash flow in 2005 will be sufficient to fund our capital and exploration budgeted spending of approximately $280 million and again provide excess cash flow. Any excess cash flow may be used for acquisitions, to pay current debt due, repurchase common stock, expand our capital program or other opportunities.

Our 2005 strategy will remain consistent with 2004 focusing on a disciplined approach to investment that balances our drilling effort between exploration opportunities and the development program, along with acquisition opportunities and a continued financial focus including stock buyback and debt repayment.

The preceding paragraphs, discussing our strategic pursuits and goals, contain forward-looking information. Please read Forward-Looking Information on page 42.

FINANCIAL CONDITION

Capital Resources and Liquidity

Our primary source of cash in 2004 was from funds generated from operations. Proceeds from the sale of common stock under stock option plans during 2004 roughly offset our repurchase of 405,100 treasury shares of Company stock at a weighted average purchase price of $38.58. The Company generates cash from the sale of natural gas and crude oil. Operating cash flow fluctuations are substantially driven by commodity prices and changes in our production volumes. Prices for crude oil and natural gas have historically been subject to seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have influenced prices throughout the recent years. Working capital is substantially influenced by these variables. Fluctuation in cash flow may result in an increase or decrease in our capital and exploration expenditures. See Results of Operations for a review of the impact of prices and volumes on sales. Cash flows provided by operating activities were primarily used to fund exploration and development expenditures, purchase treasury stock and pay dividends. See below for additional discussion and analysis of cash flow.

	Year Ended December 31,		
	2004	2003	2002
Cash Flows Provided by Operating Activities	**$ 273,022**	$ 241,638	$ 164,182
Cash Flows Used by Investing Activities	**(255,357)**	(151,856)	(138,668)
Cash Flows Used by Financing Activities	**(8,363)**	(90,660)	(27,364)
Net Increase (Decrease) in Cash and Cash Equivalents	**$ 9,302**	$ (878)	$ (1,850)

Operating Activities. Net cash provided by operating activities in 2004 increased $31.4 million over 2003. This increase is primarily due to higher commodity prices. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs. Average realized natural gas prices increased 15% over 2003, while crude oil realized prices increased 7% over the same period. Production volumes declined slightly, with a 5 percent reduction of equivalent production in 2004 compared to 2003. While we believe 2005 commodity production may exceed 2004 levels, we are unable to predict future commodity prices, and as a result cannot provide any assurance about future levels of net cash provided by operating activities.

Net cash provided by operating activities in 2003 increased $77.5 million over 2002. This increase is primarily due to higher commodity prices. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs. Average natural gas prices increased 49% over 2002, while crude oil prices increased 24% over the same period. Production volumes declined slightly with a 2% reduction of equivalent production in 2003 compared to 2002. See page 33 for a discussion on commodity prices and Results of Operations for a review of the impact of prices and volumes on sales revenue.

Investing Activities. The primary driver of cash used by investing activities is capital spending and exploration expense. We establish the budget for these amounts based on our current estimate of future commodity prices. Due to the volatility of commodity prices our budget may be periodically adjusted during any given year. Cash flows used in investing activities increased for the years ended December 31, 2004 and 2003 in the amounts of $103.5 million and $13.2 million. The increase from 2003 to 2004 is primarily due to an increase in drilling activity as a result of higher commodity prices. This increase largely occurred in our East region and the Rocky Mountain area of our West region. Our initial drilling activity in Canada also contributed to the increase. Cash flows used in investing activities increased from 2002 to 2003 due to an increase in capital spending and exploration expense in response to higher commodity prices and exploitation of acquired properties. This increase was partially offset by proceeds received from the sale of certain non-strategic assets.

Financing Activities. Cash flows used by financing activities were $8.4 million for the year ended December 31, 2004. This is the result of proceeds from the exercise of stock options, offset by the purchase of treasury shares and dividend payments. Cash flows used by financing activities for the year ended December 31, 2003 was $90.7 million. This is substantially due to a net repayment on our revolving credit facility in the amount of $95.0 million. Cash utilized for the repayments was generated from operating cash flows. The cash flows used by financing activities in 2002 is primarily due to a net repayment on our revolving credit facility of $25.0 million.

The available credit line under our revolving credit facility, which was $250 million at year end, but can be expanded up to $350 million, is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the bank's petroleum engineer) and other assets. At December 31, 2004, we had no outstanding balance on the credit facility. The revolving term of the credit facility ends in December 2009. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Management believes that we have the ability to finance through new debt or equity offerings, if necessary, our capital requirements, including acquisitions.

Our Board of Directors authorized the repurchase of two million shares of our common stock in the open market or in negotiated transactions. All purchases executed have been through open market transactions. There is no expiration date associated with the authorization to repurchase securities of the Company. See "Issuer Purchases of Equity Securities" in Item 5 "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Repurchases of Equity Securities" for additional information.

Capitalization

Information about our capitalization is as follows:

	December 31,	
(In millions)	**2004**	2003
Debt [1]	**$ 270.0**	$ 270.0
Stockholders' Equity [2] [3]	**455.7**	365.2
Total Capitalization	**$ 725.7**	$ 635.2
Debt to Capitalization [3]	**37%**	43%
Cash and Cash Equivalents	**$ 10.0**	$ 0.7

(1) *Includes $20.0 million of current portion of long term debt in 2004.*

(2) *Includes common stock, net of treasury stock.*

(3) *Includes the impact of the Accumulated Other Comprehensive Loss at December 31, 2004 and 2003 of $20.4 million and $23.1 million, respectively.*

For the year ended December 31, 2004, we paid dividends of $5.2 million on our common stock. A regular dividend of $0.04 per share of common stock has been declared for each quarter since we became a public company.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital and exploration activities, excluding major oil and gas property acquisitions, with cash generated from operations and, when necessary, our revolving credit facility. 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, 2004.

(In millions)	2004	2003	2002
Capital Expenditures			
Drilling and Facilities	**$ 174.0**	$ 102.0	$ 67.0
Leasehold Acquisitions	**18.3**	14.1	4.8
Pipeline and Gathering	**13.5**	10.6	4.1
Other	**1.6**	1.8	1.4
	207.4	128.5	77.3
Proved Property Acquisitions	**4.0**	1.5	8.8
Exploration Expense	**48.1**	58.2	40.2
Total	**$ 259.5**	$ 188.2	$ 126.3

We plan to drill about 300 gross wells in 2005 compared with 256 gross wells drilled in 2004. This 2005 drilling program includes approximately $280.0 million in total capital and exploration expenditures, up from $259.5 million in 2004. We will continue to assess the natural gas price environment and may increase or decrease the capital and exploration expenditures accordingly.

There are many factors that impact our depreciation, depletion and amortization rate. These include reserve additions and revisions, development costs, impairments and changes in anticipated production in a future period. In 2005 management expects an increase in our depreciation, depletion and amortization rate due to production declines and higher capital costs. This change may result in an increase of depreciation, depletion and amortization of 5% to 10% greater than 2004 levels. This increase will not have an impact on our cash flows.

Contractual Obligations

Our known material contractual obligations include long-term debt, interest on long-term debt and operating leases. We have no off-balance sheet debt or other similar unrecorded obligations, and we have not guaranteed the debt of any other party.

A summary of our known contractual obligations as of December 31, 2004 are set forth in the following table:

		Payments Due by Year			
(In thousands)	**Total**	2005	2006 to 2007	2008 to 2009	2010 & Beyond
Long-Term Debt[1]	**$ 270,000**	$ 20,000	$ 40,000	$ 40,000	$ 170,000
Interest on Long-Term Debt[2]	**126,405**	19,545	34,776	29,024	43,060
Firm Gas Transportation Agreements	**87,888**	8,117	13,321	7,565	58,885
Operating Leases	**17,000**	4,889	8,882	2,847	382
Total Contractual Cash Obligations	**$ 501,293**	**$ 52,551**	**$ 96,979**	**$ 79,436**	**$ 272,327**

(1) *Including current portion.*

(2) *Interest payments have been calculated utilizing the fixed rate of our $270 million long-term debt outstanding at December 31, 2004. At December 31, 2004 we had no outstanding debt on our revolving credit facility. See Note 5 of the Notes to the Consolidated Financial Statements for details of long-term debt.*

Amounts related to our asset retirement obligations are not included in the above table given the uncertainty regarding the actual timing of such expenditures. The total amount of asset retirement obligations at December 31, 2004 is $40.4 million.

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 most significant policies are discussed below.

Oil and Gas Reserves

The process of estimating quantities of proved reserves is inherently uncertain, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysic, engineering and production data. The extent, quality and reliability of this technical data can vary. The degree of uncertainty varies among the three regions in which we operate. The estimation of reserves in the Gulf Coast region requires more estimates than the East and West regions and inherently has more uncertainty surrounding reserve estimation. The differences in the reserve estimation process are substantially due to the geological conditions in which the wells are drilled. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as oil and gas prices. Additional assumptions include 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.

In 2004, 2003 and 2002, 100% of our reserves were subject to an external review by Miller & Lents, Ltd., an independent oil and gas reservoir engineering consulting firm, who in their opinion determined the estimates to be reasonable in the aggregate. Additionally, in 2004, 2003 and 2002, we did not have a significant reserve revision recorded. For more information regarding reserve estimation, including historical reserve revisions, refer to the Supplemental Oil and Gas Disclosure beginning on page 85.

Our rate of recording depreciation, depletion and amortization expense (DD&A) is dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from lower market prices, which may make it non-economic to drill for and produce higher cost fields. A five percent positive or negative revision to proved reserves throughout the Company would decrease or increase the DD&A rate by approximately $0.04 to $0.05 per Mcfe. Revisions in significant fields may individually affect our DD&A rate. It is estimated that a positive or negative reserve revision of 10% in one of our most productive fields would have a $0.02 impact on our total DD&A rate.

In addition, a 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." Due to the inherent imprecision of the reserve estimation process, risks associated with the operations of proved producing properties, and market sensitive commodity prices utilized in our impairment analysis, management cannot determine if an impairment is reasonably likely to occur in the future.

Carrying Value of Oil and Gas Properties

We evaluate the impairment of our oil and gas properties on a lease-by-lease basis whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted cash flows, based on our estimate of future crude oil and natural gas prices, operating costs and anticipated production from proved reserves are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. Fair value is calculated by discounting the future cash flows. In 2002 there were no unusual or unexpected occurrences that caused significant revisions in estimated cash flows which were utilized in our impairment test. In 2003 we significantly revised the estimated cash flow utilized in our impairment review of the Kurten field due to a loss of a reversionary interest in the field. In December 2003 our remaining interest in the field was sold. For additional discussion on the Kurten field impairment see Note 2 to the consolidated financial statements. In 2004 there were no unusual or unexpected occurrences that caused significant revisions in estimated cash flows which were utilized in our impairment test.

Costs attributable to our unproved properties are not subject to the impairment analysis described above, however, a portion of the costs associated with such properties is subject to amortization based on past experience and average property lives. Average property lives are determined on a regional basis and based on the estimated life of unproved property leasehold rights. Historically, the average property lives in each of the regions have not significantly changed. However, if the average property life increases, the amount of the amortization charge in a given reporting period will decrease. If the average unproved property life decreases or increases by one year the amortization would increase by approximately $2.3 million or decrease by approximately $1.9 million, respectively per year.

In the past the average leasehold life in the Gulf Coast region has been shorter than the average life in the East and West regions. Average property lives in the Gulf Coast, East and West regions have been four, six and six years, respectively. Average property lives in Canada are estimated to be five years. As these properties are developed and reserves are proven, the remaining capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year the determination is made. The rate at which the unproved properties are written off depends on the timing and success of our future exploration program.

Accounting for Derivative Instruments and Hedging Activities

Periodically we enter into derivative commodity instruments to hedge our exposure to price fluctuations on natural gas and crude oil production. We follow the accounting prescribed in SFAS 133. Under SFAS 133, the fair value of each derivative instrument is recorded as either an asset or liability on the balance sheet. At the end of each period, these instruments are marked-to-market. The gain or loss on the change in fair value is recorded as Other Comprehensive Income, a component of equity, to the extent that the derivative instrument is designated as an effective hedge. Under SFAS 133, effectiveness is a measurement of how closely correlated the hedge instrument is with the underlying physical sale. For example, a natural gas price swap that converts Henry Hub index to a fixed price would be perfectly correlated, and 100% effective, if the underlying gas were sold at the Henry Hub index. Any portion of the gains or losses that are considered ineffective under the SFAS 133 test are recorded immediately as a component of operating revenue on the statement of operations.

Long-Term Employee Benefit Costs

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

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

The benefit obligation and the periodic cost of postretirement medical benefits also are measured based on assumed rates of future increase in the per capita cost of covered health care benefits. As of December 31, 2004, the assumed rate of increase was 10.0%. The net periodic cost of pension benefits included in expense also is affected by the expected long-term rate of return on plan assets assumption. The expected return on plan assets rate is normally changed less frequently than the assumed discount rate, and reflects long-term expectations, rather than current fluctuations in market conditions. The actual rate of return on plan assets may differ from the expected rate due to the volatility normally experienced in capital markets. Management's goal is to manage the investments over the long term to achieve optimal returns with an acceptable level of risk and volatility.

Stock Based Compensation

Prior to the issuance of SFAS 123R "Share Based Payment", there were two alternative methods that could be used to account for stock-based compensation. The first method is the Intrinsic Value method and recognizes compensation cost as the excess, if any, of the quoted market price of our stock at the grant date over the amount an employee must pay to acquire the stock. The second method is the Fair Value method. Under the fair value method, compensation cost is measured at the grant date based on the value of an award and is recognized over the service period, which is usually the vesting period. Currently, we account for stock-based compensation in accordance with the Intrinsic Value method. SFAS 123R requires that the fair value of stock options and any other equity-based compensation must be expensed at the grant date. To calculate the fair value, either a binomial or Black-Scholes valuation model may be used. We currently expense performance share awards; however, beginning in the third quarter of 2005, we will be required to expense all stock based compensation. Further discussion of SFAS 123R and stock compensation is included in "Recently Issued Accounting Pronouncements" on page 41.

OTHER ISSUES AND CONTINGENCIES

Corporate Income Tax. We generated tax credits for the production of certain qualified fuels, including natural gas produced from tight sands formations and Devonian Shale. The credit for natural gas from a tight sand formation (tight gas sands) amounted to $0.52 per Mmbtu for natural gas sold prior to 2003 from qualified wells drilled in 1991 and 1992. A number of wells drilled in the East region and Rocky Mountains during 1991 and 1992 qualified for the tight gas sands tax credit. The credit for natural gas produced from Devonian Shale was $1.09 per Mmbtu in 2002. In 1995 and 1996, we completed three transactions to monetize the value of these tax credits, resulting in revenues of $2.0 million in 2002. The tax credit wells were repurchased in December 2002 and no tax credits were generated in 2003 or 2004 as the credits expired in 2002. See Note 13 of the Notes to the Consolidated Financial Statements for further discussion.

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

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

Restrictive Covenants**.** Our ability to incur debt and to make certain types of investments is subject to certain restrictive covenants in the Company's various debt instruments. Among other requirements, our Revolving Credit Agreement and the Notes 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, 2004, we are in compliance with all restrictive covenants on both the Revolving Credit Agreement and the Notes. In the unforeseen event that we fail to comply with these covenants, the Company may apply for a temporary waiver with the lender, which, if granted, would allow us a period of time to remedy the situation. See further discussion in Capital Resources and Liquidity.

Limited Partnership. As part of the 2001 Cody acquisition, we acquired an interest in certain oil and gas properties in the Kurten field, as general partner of a partnership and as an operator. We had approximately a 25% interest in the field, including a one percent interest in the partnership. Under the partnership agreement, we had the right to a reversionary working interest that would bring our ultimate interest to 50% upon the limited partner reaching payout. Based on the addition of this reversionary interest, and because the field has over a 40-year reserve life, approximately $91 million was allocated to this field under purchase accounting at the time of the acquisition. Additionally, the limited partner had the sole option to trigger a liquidation of the partnership.

Effective February 13, 2003, liquidation of the partnership commenced at the election of the limited partner. The limited partner was a financial entity and not an industry operator. Their decision to liquidate was based upon their perception that the value of their investment in the partnership had increased due to an increase in underlying commodity prices, primarily oil, since their investment in 1999. We proceeded with the liquidation to avoid having a minority interest in a non-operated water flood field for which the new operator was not designated at the time of liquidation. In connection with the liquidation, an appraisal was required to be obtained to allocate the interest in the partnership assets. Additionally, we were required to test the field for recoverability in accordance with FAS 144. Pursuant to the terms of the partnership agreement and based on the appraised value of the partnership assets it was not possible for us to obtain the reversionary interest as part of the liquidation. Due to the impact of the loss of the reversionary interest on future estimated net cash flows of the Kurten field, the limited partner's decision and our decision to proceed with the liquidation, an impairment review was performed which required an after-tax impairment charge in the first quarter of 2003 of $54.4 million. This impairment charge is reflected in the 2003 Statement of Operations as an operating expense but did not impact our cash flows.

Operating Risks and Insurance Coverage. Our business involves a variety of operating risks, including:

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

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

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

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

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

Recently Issued Accounting Pronouncements

In May 2004, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." This FSP provides guidance on the accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) for employers that sponsor postretirement health care plans that provide prescription drug benefits. This FSP also requires those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Act (the subsidy). This FSP supersedes FSP 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" and is effective for the first interim period beginning after June 15, 2004. Our current accumulated projected benefit obligation and net periodic postretirement benefit cost does not reflect any amount associated with the subsidy. Furthermore, in 2004, we amended our postretirement benefit plan to exclude prescription drug benefits for participants age 65 and older effective January 1, 2006. The adoption of this FSP is not expected to impact our operating results, financial position or cash flows.

In November 2004, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 151, "Inventory Costs - an amendment of ARB No. 43, Chapter 4" in an effort to unite the United States accounting standards for inventories with International Accounting Standards leading to consistent application of certain accounting requirements. FAS 151 addresses accounting for abnormal amounts of freight, handling costs, idle facility expense and spoilage (wasted material) and requires that these costs be recognized as current period expenses. Previously, these costs had to be categorized as "so abnormal as to require treatment as current period charges." In addition, allocation of fixed production overheads to the costs of conversion must be based on the normal capacity of the production facilities. FAS 151 will be effective for fiscal periods beginning after June 15, 2005. The adoption of this statement is not expected to impact our operating results, financial position or cash flows.

In December 2004, the FASB issued SFAS 153 "Exchanges of Nonmonetary Assets – an amendment of APB Opinion No. 29." This statement requires that nonmonetary exchanges must be recorded at fair value and the appropriate gain or loss must be recognized so long as the fair value is determinable and the transaction has commercial substance. According to this statement, companies can no longer use the "similar productive assets" concept to account for nonmonetary exchanges at book value with no gain or loss being recognized. FAS 153 will be effective for fiscal periods beginning after June 15, 2005. The adoption of this statement may impact our operating results, financial position or cash flows in future periods if such a nonmonetary exchange occurs.

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment." SFAS 123R revises SFAS 123, "Accounting for Stock-Based Compensation", and focuses on accounting for share-based payments for services by employer to employee. The statement requires companies to expense the fair value of employee stock options and other equity-based compensation at the grant date. The statement does not require a certain type of valuation model and either a binomial or Black-Scholes model may be used. The provisions of SFAS 123R are effective for financial statements for fiscal periods ending after June 15, 2005. We are currently evaluating the method of adoption and the impact on our operating results. Our future cash flows will not be impacted by the adoption of this standard. See Footnote 1 "Stock Based Compensation" for further information.

In February 2005, the FASB released for public comment proposed Staff Position FAS 19-a "Accounting for Suspended Well Costs." This proposed staff position would amend FASB Statement No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" and provides guidance about exploratory well costs to companies who use the successful efforts method of accounting. The proposed position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserved are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well's economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional disclosures are required to provide information about management's evaluation of capitalized exploratory well costs. In addition, the Staff Position requires the disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. Although this Staff Position is not final and has not been adopted by us, we have included the additional disclosures in Note 2. Comments on this proposed FSP are expected by March 7, 2005.

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

2004 and 2003 Compared

We reported net income for the year ended December 31, 2004 of $88.4 million, or $2.72 per share. During 2003, we reported net income of $21.1 million, or $0.66 per share. Operating income increased by $94.1 million compared to the prior year, from $66.6 million to $160.7 million. The increase in net income and operating income was principally due to decreased operating expenses from 2003 to 2004 related to the decrease in impairments of oil and gas properties of $90.3 million related to the loss in 2003 of a reversionary interest in the Kurten field. In addition, the increases in operating income and net income were due to an increase in our realized natural gas and crude oil prices.

Natural Gas Production Revenues. Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $5.20 per Mcf compared to $4.51 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instruments which reduced these prices by $0.76 per Mcf in 2004 and $0.68 per Mcf in 2003. The following table excludes the unrealized gain from the change in derivative fair value of $0.9 million and the unrealized loss of $1.5 million for the years ended December 31, 2004 and 2003, respectively. These unrealized changes in fair value have been included in the Natural Gas Production revenues line item on the Statement of Operations.

	Year Ended December 31,		Variance	
	2004	2003	Amount	Percent
Natural Gas Production *(Mmcf)*				
Gulf Coast	**31,358**	29,550	1,808	6%
West	**21,866**	23,776	(1,910)	(8%)
East	**19,442**	18,580	862	5%
Canada	**167**	—	167	—
Total Company	**72,833**	71,906	927	1%
Natural Gas Production Sales Price *($/Mcf)*				
Gulf Coast	**$ 5.27**	$ 4.78	$ 0.49	10%
West	**$ 4.75**	$ 3.67	$ 1.08	29%
East	**$ 5.60**	$ 5.15	$ 0.45	9%
Canada	**$ 4.69**	$ —	$ 4.69	—
Total Company	**$ 5.20**	$ 4.51	$ 0.69	15%
Natural Gas Production Revenue *(In thousands)*				
Gulf Coast	**$ 165,177**	$ 141,107	$ 24,070	17%
West	**103,851**	87,245	16,606	19%
East	**108,935**	95,672	13,263	14%
Canada	**784**	—	784	—
Total Company	**$ 378,747**	$ 324,024	$ 54,723	17%
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
Gulf Coast	**$ 15,434**			
West	**23,613**			
East	**8,828**			
Canada	**784**			
Total Company	**$ 48,659**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
Gulf Coast	**$ 8,635**			
West	**(7,009)**			
East	**4,438**			
Canada	**—**			
Total Company	**$ 6,064**			

The increase in natural gas production revenues was mainly a result of increased sales prices as well as the increase in overall production. Natural gas production was up slightly from the prior year and production revenues also increased from 2003. Natural gas production increased slightly in all regions except the West region, where the decline in production was due to lower capital spending in 2003 and continued natural decline. The increases in both sales price and production resulted in an increase in natural gas production revenues of $54.7 million.

Brokered Natural Gas Revenues and Costs

	Year Ended December 31,		Variance	
	2004	2003	Amount	Percent
Sales Price *($/Mcf)*	**$ 6.56**	$ 5.16	$ 1.40	27%
Volume Brokered *(Mmcf)*	**12,876**	18,557	(5,681)	(31%)
Brokered Natural Gas Revenues *(In thousands)*	**$ 84,416**	$ 95,754		
Purchase Price *($/Mcf)*	**$ 5.84**	$ 4.64	$ 1.20	26%
Volume Brokered *(Mmcf)*	**12,876**	18,557	(5,681)	(31%)
Brokered Natural Gas Cost *(In thousands)*	**$ 75,217**	$ 86,104		
Brokered Natural Gas Margin *(In thousands)*	**$ 9,199**	$ 9,650	$ (451)	(5%)
(In thousands)				
Sales Price Variance Impact on Revenue	**$ 18,026**			
Volume Variance Impact on Revenue	**$ (29,363)**			
	$(119,337)			
(In thousands)				
Purchase Price Variance Impact on Purchases	**$ (15,451)**			
Volume Variance Impact on Purchases	**$ 26,338**			
	$ 10,887			

The decrease in brokered natural gas revenues of $11.3 million combined with the decline in brokered natural gas cost of $10.9 million resulted in a decrease to the brokered natural gas margin of $0.5 million.

Crude Oil and Condensate Revenues. Our average total company realized crude oil sales price, including the realized impact of derivative instruments, was $31.55 per Bbl compared to $29.55 per Bbl for 2003. These prices include the realized impact of derivative instruments which reduced these prices by $8.98 per Bbl in 2004 and $1.41 per Bbl in 2003. The following table excludes the unrealized loss from the change in derivative fair value of $2.9 million and $1.9 million for the year ended December 31, 2004 and 2003, respectively. These unrealized changes in fair value have been included in the Crude Oil and Condensate revenues line item on the Statement of Operations.

	Year Ended December 31,		Variance	
	2004	2003	Amount	Percent
Crude Oil Production *(Mbbl)*				
Gulf Coast	**1,805**	2,591	(786)	(30%)
West	**159**	188	(29)	(15%)
East	**27**	27	—	—
Canada	**4**	—	4	—
Total Company	**1,995**	2,806	(811)	(29%)
Crude Oil Sales Price *($/Bbl)*				
Gulf Coast	**$ 30.67**	$ 29.48	$ 1.19	4%
West	**$ 40.29**	$ 30.11	$ 10.18	34%
East	**$ 38.28**	$ 32.65	$ 5.63	17%
Canada	**$ 37.93**	$ —	$ 37.93	—
Total Company	**$ 31.55**	$ 29.55	$ 2.00	7%
Crude Oil Revenue *(In thousands)*				
Gulf Coast	**$ 55,357**	$ 76,375	$ (21,018)	(28%)
West	**6,404**	5,675	729	13%
East	**1,049**	870	179	21%
Canada	**129**	—	129	—
Total Company	**$ 62,939**	$ 82,920	$ (19,981)	(24%)
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
Gulf Coast	**$ 2,151**			
West	**1,604**			
East	**179**			
Canada	**129**			
Total Company	**$ 4,063**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
Gulf Coast	**$ (23,169)**			
West	**(875)**			
East	**—**			
Canada	**—**			
Total Company	**$ (24,044)**			

The decline in crude oil production is due to emphasis on natural gas in the Gulf Coast drilling program, along with the natural decline of existing production in south Louisiana. The increase in the realized crude oil price combined with the decline in production resulted in a net revenue decrease of $20.0 million.

Other Operating Revenues. Other operating revenues decreased $3.7 million. This change was primarily a result of decreases in natural gas transportation revenue and natural gas liquid revenue for the year ended December 31, 2004.

Operating Expenses. Total costs and expenses from operations decreased $85.3 million for the year ended December 31, 2004 compared to the year ended December 31, 2003. The primary reasons for this fluctuation are as follows:

- Brokered natural gas cost decreased $10.9 million. For additional information related to this decrease see the analysis performed for Brokered Natural Gas Revenue and Cost.
- Exploration expense decreased $10.0 million primarily as a result of higher dry hole expense in 2003. During 2004, we drilled 5 dry exploratory wells compared to 15 in the corresponding period of 2003.
- Depreciation, Depletion and Amortization increased, as anticipated, by approximately 9% or $8.4 million. The increase was primarily due to negative reserve revisions in south Louisiana in 2003, which increased the per Mcfe DD&A rate.
- Impairment of producing properties expense decreased $90.3 million. This decrease is substantially related to a pre-tax non-cash impairment charge of $87.9 million related to the loss of a reversionary interest in the Kurten field incurred in 2003 as discussed below in the "Operating Expenses" section of "2003 and 2002 Compared."
- General and Administrative expense increased $9.6 million from 2003 to 2004. Stock compensation expense increased by $4.9 million as a result of performance share awards issued in 2004 and increased amortization of restricted stock grants for grants which occurred during the year. Compliance fees related to Sarbanes-Oxley increased expenses by $2.3 million, and there was a $1.2 million increase in employee related expenses.
- Taxes other than income increased $3.9 million as a result of higher commodity prices realized in the year ended 2004 as compared to the same period of the prior year.

Interest Expense. Interest expense decreased $1.7 million. This variance is due to a lower average level of outstanding debt on the revolving credit facility offset somewhat by an increase in Prime rates. Average daily borrowings under the revolving credit facility during the year were $0.5 million in 2004 which is a decrease from $0.7 million in 2003. Our other remaining debt is at fixed interest rates.

Income Tax Expense. Income tax expense increased $35.2 million due to a comparable increase in our pre-tax net income.

2003 and 2002 Compared

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

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

	Year Ended December 31,		Variance	
	2003	2002	Amount	Percent
Natural Gas Production *(Mmcf)*				
Gulf Coast	29,550	30,408	(858)	(3%)
West	23,776	25,308	(1,533)	(6%)
East	18,580	17,953	626	3%
Total Company	71,906	73,670	(1,764)	(2%)
Natural Gas Production Sales Price *($/Mcf)*				
Gulf Coast	$ 4.78	$ 3.34	$ 1.44	43%
West	$ 3.67	$ 2.39	$ 1.28	54%
East	$ 5.15	$ 3.38	$ 1.77	52%
Total Company	$ 4.51	$ 3.02	$ 1.49	49%
Natural Gas Production Revenue *(In thousands)*				
Gulf Coast	$ 141,107	$ 101,525	$ 39,582	39%
West	$ 87,245	$ 60,563	$ 26,682	44%
East	$ 95,672	$ 60,696	$ 34,976	58%
Total Company	$ 324,024	$ 222,784	$101,240	45%
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
Gulf Coast	$ 42,446			
West	$ 30,349			
East	$ 32,859			
Total Company	$ 105,654			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
Gulf Coast	$ (2,864)			
West	$ (3,667)			
East	$ 2,117			
Total Company	$ (4,414)			

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

Brokered Natural Gas Revenues and Cost

	Year Ended December 31, 2003	Year Ended December 31, 2002	Variance Amount	Variance Percent
Sales Price *($/Mcf)*	$ 5.16	$ 3.12	$ 2.04	65%
Volume Brokered *(Mmcf)*	18,557	18,807	(250)	(1%)
Brokered Natural Gas Revenues *(In thousands)*	$ 95,754	$ 58,678		
Purchase Price *($/Mcf)*	$ 4.64	$ 2.82	$ 1.82	65%
Volume Brokered *(Mmcf)*	18,557	18,807	(250)	(1%)
Brokered Natural Gas Cost *(In thousands)*	$ 86,104	$ 53,036		
Brokered Natural Gas Margin *(In thousands)*	$ 9,650	$ 5,642	$ 4,008	71%

(In thousands)	
Sales Price Variance Impact on Revenue	$ 37,856
Volume Variance Impact on Revenue	$ (780)
	$ 37,076

(In thousands)	
Purchase Price Variance Impact on Purchases	$ (33,774)
Volume Variance Impact on Purchases	$ 705
	$ (33,069)

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

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

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

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

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

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

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

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

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

ITEM 7A. Quantitative and Qualitative Disclosures about Market Risk

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

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and, to a lesser extent, oil. Declines in oil and natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil and gas prices also may reduce the amount of oil and gas that we can produce economically. Historically, oil and gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

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

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

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

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

Derivative Instruments and Hedging Activity

Periodically, we enter into derivative commodity instruments to hedge our exposure to price fluctuations on natural gas and crude oil production. At December 31, 2004, we had 15 cash flow hedges open: 7 natural gas price collar arrangements, one crude oil collar arrangement and 7 natural gas price swap arrangements. Additionally, we had two crude oil financial instruments open at December 31, 2004, that did not qualify for hedge accounting under SFAS 133. At December 31, 2004, a $28.8 million ($17.8 million net of tax) unrealized loss was recorded to Other Comprehensive Income, along with a $38.4 million derivative liability and a $2.9 million derivative receivable. The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Other Comprehensive Income. The ineffective portion, if any, of the change in the fair value of derivatives designated as hedges, and the change in fair value of all other derivatives is recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate revenue, as appropriate.

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

	Year Ended December 31,					
	2004		2003		2002	
(In thousands)	**Realized**	**Unrealized**	Realized	Unrealized	Realized	Unrealized
Operating Revenues –						
Increase / (Decrease) to Revenue						
Natural Gas Production	**$ (55,008)**	**$ 914**	$ (48,829)	$ (1,468)	$ (574)	$ (1,683)
Crude Oil	**(17,908)**	**(2,917)**	(3,963)	(1,879)	(5,202)	(693)

Assuming no change in commodity prices, after December 31, 2004 we would reclassify to earnings, over the next 12 months, $17.8 million in after-tax expenditures associated with commodity derivatives. This reclassification represents the net liability associated with open positions currently not reflected in earnings at December 31, 2004 related to anticipated 2005 production.

Hedges on Production - Swaps

From time to time, we enter into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of our production. These derivatives are not held for trading purposes. Under these price swaps, we receive a fixed price on a notional quantity of natural gas and crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures. Under our Revolving Credit Agreement, the aggregate level of commodity hedging must not exceed 100% of the anticipated future equivalent production during the period covered by these cash flow hedges. During 2004, natural gas price swaps covered 29,617 Mmcf, or 41% of our gas production, fixing the sales price of this gas at an average of $5.04 per Mcf.

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

	Natural Gas Price Swaps		
Contract Period	Volume in Mmcf	Weighted Average Contract Price	Unrealized Gain / (Loss) *(In thousands)*
As of December 31, 2004			
Natural Gas Price Swaps on Production in:			
First Quarter 2005	5,069	$ 5.14	
Second Quarter 2005	5,125	5.14	
Third Quarter 2005	5,181	5.14	
Fourth Quarter 2005	5,181	5.14	
Full Year 2005	**20,556**	**$ 5.14**	**$ (27,897)**

From time to time we enter into natural gas and crude oil derivative arrangements that do not qualify for hedge accounting under SFAS 133. These financial instruments are recorded at fair value at the balance sheet date. At December 31, 2004, we had two open crude oil swap arrangements with an unrealized net loss of $5.5 million recognized in Operating Revenues.

Hedges on Production - Options

From time to time, we enter into natural gas and crude oil collar agreements with counterparties to hedge price risk associated with a portion of our production. These cash flow hedges are not held for trading purposes. Under the collar arrangements, if the index price rises above the ceiling price, we pay the counterparty. If the index falls below the floor price, the counterparty pays us. During 2004, natural gas price collars covered 22,954 Mmcf of our gas production, or 32% of our gas production with a weighted average floor of $4.78 per Mcf and a weighted average ceiling of $6.06 per Mcf.

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

	Natural Gas Price Collars		
Contract Period	Volume in Mmcf	Weighted Average Ceiling / Floor	Unrealized Gain / (Loss) *(In thousands)*
As of December 31, 2004			
First Quarter 2005	4,982	$9.09/$6.16	
Second Quarter 2005	3,367	8.38/5.30	
Third Quarter 2005	3,404	8.38/5.30	
Fourth Quarter 2005	3,404	8.38/5.30	
Full Year 2005	**15,157**	**$8.61/$5.59**	**$ (2,500)**

At December 31, 2004, we had one open crude oil price collar contract covering our 2005 production as follows:

	Crude Oil Price Collar		
Contract Period	Volume in Mbbl	Weighted Average Ceiling / Floor	Unrealized Gain / (Loss) *(In thousands)*
As of December 31, 2004			
First Quarter 2005	90	$50.50/$40.00	
Second Quarter 2005	91	50.50/40.00	
Third Quarter 2005	92	50.50/40.00	
Fourth Quarter 2005	92	50.50/40.00	
Full Year 2005	**365**	**$50.50/$40.00**	**$ 454**

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

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future market prices of energy commodities. See Forward-Looking Information on page 42.

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 the 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

(In thousands)	December 31, 2004 Carrying Amount	December 31, 2004 Estimated Fair Value	December 31, 2003 Carrying Amount	December 31, 2003 Estimated Fair Value
Debt				
7.19% Notes	$ 80,000	$ 87,770	$ 100,000	$ 113,673
7.26% Notes	75,000	85,849	75,000	87,345
7.36% Notes	75,000	87,111	75,000	87,770
7.46% Notes	20,000	23,804	20,000	24,214
Credit Facility	—	—	—	—
	$ 250,000	$ 284,534	$ 270,000	$ 313,002

ITEM 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed an integrated audit of Cabot Oil & Gas Corporation's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

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, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements 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 12 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" effective January 1, 2003.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Houston, Texas
March 2, 2005

CONSOLIDATED STATEMENT OF OPERATIONS

(In thousands, except per share amounts)

	Year Ended December 31,		
	2004	2003	2002
OPERATING REVENUES			
Natural Gas Production	**$ 379,661**	$ 322,556	$ 221,101
Brokered Natural Gas	**84,416**	95,816	58,729
Crude Oil and Condensate	**60,022**	81,040	67,548
Other	**6,309**	9,979	6,378
	530,408	509,391	353,756
OPERATING EXPENSES			
Brokered Natural Gas Cost	**75,217**	86,162	53,007
Direct Operations - Field and Pipeline	**53,581**	50,399	50,047
Exploration	**48,130**	58,119	40,167
Depreciation, Depletion and Amortization	**103,343**	94,903	96,512
Impairment of Unproved Properties	**10,145**	9,348	9,348
Impairment of Oil & Gas Properties (Note 2)	**3,458**	93,796	2,720
General and Administrative	**34,735**	25,112	28,377
Taxes Other Than Income	**41,022**	37,138	24,734
	369,631	454,977	304,912
Gain (Loss) on Sale of Assets	**(124)**	12,173	244
INCOME FROM OPERATIONS	**160,653**	66,587	49,088
Interest Expense and Other	**22,029**	23,545	25,311
Income Before Income Taxes and Cumulative Effect of Accounting Change	**138,624**	43,042	23,777
Income Tax Expense	**50,246**	15,063	7,674
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	**88,378**	27,979	16,103
CUMULATIVE EFFECT OF ACCOUNTING CHANGE (Note 12)	**—**	(6,847)	—
NET INCOME	**$ 88,378**	$ 21,132	$ 16,103
Basic Earnings Per Share - Before Accounting Change	**$ 2.72**	$ 0.87	$ 0.51
Diluted Earnings Per Share - Before Accounting Change	**$ 2.69**	$ 0.87	$ 0.50
Basic Loss Per Share - Accounting Change	**$ —**	$ (0.21)	$ —
Diluted Loss Per Share - Accounting Change	**$ —**	$ (0.21)	$ —
Basic Earnings Per Share	**$ 2.72**	$ 0.66	$ 0.51
Diluted Earnings Per Share	**$ 2.69**	$ 0.65	$ 0.50
Average Common Shares Outstanding	**32,488**	32,050	31,737
Diluted Common Shares (Note 14)	**32,893**	32,290	32,076

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

CONSOLIDATED BALANCE SHEET

(In thousands, except share amounts)

	December 31,	
	2004	2003
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	**$ 10,026**	$ 724
Accounts Receivable	**125,754**	87,425
Inventories	**24,049**	18,241
Deferred Income Taxes	**21,345**	21,935
Other	**13,505**	15,006
Total Current Assets	**194,679**	143,331
PROPERTIES AND EQUIPMENT, NET (Successful Efforts Method)	**994,081**	895,955
Deferred Income Taxes	**14,855**	8,920
OTHER ASSETS	**7,341**	6,850
	$ 1,210,956	$ 1,055,056
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	**$ 104,969**	$ 84,943
Current Portion of Long-Term Debt	**20,000**	—
Deferred Income Taxes	**944**	1,826
Accrued Liabilities	**70,976**	69,758
Total Current Liabilities	**196,889**	156,527
LONG-TERM DEBT	**250,000**	270,000
DEFERRED INCOME TAXES	**247,376**	208,955
OTHER LIABILITIES	**61,029**	54,377
COMMITMENTS AND CONTINGENCIES (Note 8)		
STOCKHOLDERS' EQUITY		
Common Stock:		
Authorized - 80,000,000 Shares of $.10 Par Value		
Issued and Outstanding – 33,120,610 Shares and 32,538,255 Shares in 2004 and 2003, Respectively	**3,312**	3,254
Additional Paid-in Capital	**381,781**	361,699
Retained Earnings	**110,935**	27,763
Accumulated Other Comprehensive Loss	**(20,351)**	(23,135)
Less Treasury Stock, at Cost:		
707,700 and 302,600 Shares in 2004 and 2003, Respectively	**(20,015)**	(4,384)
Total Stockholders' Equity	**455,662**	365,197
	$ 1,210,956	$ 1,055,056

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

CONSOLIDATED STATEMENT OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 88,378**	$ 21,132	$ 16,103
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Cumulative Effect of Accounting Change	**—**	6,847	—
Depletion, Depreciation and Amortization	**103,343**	94,903	96,512
Impairment of Unproved Properties	**10,145**	9,348	9,348
Impairment of Long-Lived Assets	**3,458**	93,796	2,720
Deferred Income Tax Expense	**31,769**	(9,837)	7,882
(Gain) / Loss on Sale of Assets	**124**	(12,173)	(244)
Exploration Expense	**48,130**	58,119	40,167
Change in Derivative Fair Value	**2,003**	3,347	2,376
Performance Share Compensation	**3,429**	—	—
Other	**3,475**	885	3,888
Changes in Assets and Liabilities:			
Accounts Receivable	**(39,404)**	(17,397)	(19,317)
Inventories	**(5,808)**	(2,989)	2,308
Other Current Assets	**3,255**	(9,208)	3,976
Other Assets	**(491)**	163	(4,307)
Accounts Payable and Accrued Liabilities	**17,231**	7,041	7,342
Other Liabilities	**3,985**	(2,339)	(4,572)
Net Cash Provided by Operating Activities	**273,022**	241,638	164,182
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital Expenditures	**(207,346)**	(122,018)	(103,189)
Proceeds from Sale of Assets	**119**	28,281	4,688
Exploration Expense	**(48,130)**	(58,119)	(40,167)
Net Cash Used by Investing Activities	**(255,357)**	(151,856)	(138,668)
CASH FLOWS FROM FINANCING ACTIVITIES			
Increase in Debt	**187,000**	248,655	180,000
Decrease in Debt	**(187,000)**	(341,000)	(205,746)
Sale of Common Stock Proceeds	**12,474**	6,728	3,461
Purchase of Treasury Stock	**(15,631)**	—	—
Dividends Paid	**(5,206)**	(5,043)	(5,079)
Net Cash Used by Financing Activities	**(8,363)**	(90,660)	(27,364)
Net Increase (Decrease) in Cash and Cash Equivalents	**9,302**	(878)	(1,850)
Cash and Cash Equivalents, Beginning of Period	**724**	1,602	3,452
Cash and Cash Equivalents, End of Period	**$ 10,026**	$ 724	$ 1,602

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

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(In thousands)

	Common Shares	Stock Par	Treasury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total
Balance at December 31, 2001	31,905	$ 3,191	303	$ (4,384)	$ 346,260	$ 835	$ 650	$ 346,552
Net Income							16,103	16,103
Exercise of Stock Options	209	20			3,845			3,865
Cash Dividends at $0.16 per Share							(5,079)	(5,079)
Other Comprehensive Loss						(13,774)		(13,774)
Stock Grant Vesting	19	2			2,988			2,990
Balance at December 31, 2002	32,133	$ 3,213	303	$ (4,384)	$ 353,093	$ (12,939)	$ 11,674	$ 350,657
Net Income							21,132	21,132
Exercise of Stock Options	345	35			7,733			7,768
Cash Dividends at $0.16 per Share							(5,043)	(5,043)
Other Comprehensive Loss						(10,196)		(10,196)
Stock Grant Vesting	60	6			873			879
Balance at December 31, 2003	32,538	$ 3,254	303	$ (4,384)	$ 361,699	$ (23,135)	$ 27,763	$ 365,197
Net Income							88,378	88,378
Exercise of Stock Options	529	53			15,060			15,113
Purchase of Treasury Stock			405	(15,631)				(15,631)
Performance Share Awards					2,394			2,394
Stock Grant Vesting	54	5			2,628			2,633
Cash Dividends at $0.16 per Share							(5,206)	(5,206)
Other Comprehensive Income						2,784		2,784
Balance at December 31, 2004	**33,121**	**$ 3,312**	**708**	**$ (20,015)**	**$ 381,781**	**$ (20,351)**	**$ 110,935**	**$ 455,662**

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(In thousands)

	Year Ended December 31,		
	2004	2003	2002
Net Income	**$ 88,378**	$ 21,132	$ 16,103
Other Comprehensive Income (Loss)			
Reclassification Adjustment for Settled Contracts	**53,516**	47,926	6,230
Changes in Fair Value of Hedge Positions	**(48,494)**	(63,014)	(26,361)
Adjustment to Recognize Minimum Pension Liability	**(1,404)**	(1,333)	(2,177)
Foreign Currency Translation Adjustment	**662**	(5)	—
Deferred Income Tax	**(1,496)**	6,230	8,534
Total Other Comprehensive Income (Loss)	**2,784**	(10,196)	(13,774)
Comprehensive Income	**$ 91,162**	$ 10,936	$ 2,329

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 Nature of Operations

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

The consolidated financial statements contain the accounts of the Company after eliminating all significant intercompany balances and transactions. Certain prior year amounts have been reclassified to conform to the current year presentation.

Recently Issued Accounting Pronouncements

In May 2004, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." This FSP provides guidance on the accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) for employers that sponsor postretirement health care plans that provide prescription drug benefits. This FSP also requires those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Act (the subsidy). This FSP supersedes FSP 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" and is effective for the first interim period beginning after June 15, 2004. The Company's current accumulated projected benefit obligation and net periodic postretirement benefit cost does not reflect any amount associated with the subsidy. Furthermore, in 2004, the Company amended its postretirement benefit plan to exclude prescription drug benefits for participants age 65 and older effective January 1, 2006. The adoption of this FSP is not expected to impact the Company's operating results, financial position or cash flows.

In November 2004, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 151, "Inventory Costs – an amendment of ARB No. 43, Chapter 4" in an effort to unite the United States accounting standards for inventories with International Accounting Standards leading to consistent application of certain accounting requirements. FAS 151 addresses accounting for abnormal amounts of freight, handling costs, idle facility expense and spoilage (wasted material) and requires that these costs be recognized as current period expenses. Previously, these costs had to be categorized as "so abnormal as to require treatment as current period charges." In addition, allocation of fixed production overheads to the costs of conversion must be based on the normal capacity of the production facilities. FAS 151 will be effective for fiscal periods beginning after June 15, 2005. The adoption of this statement is not expected to impact the Company's operating results, financial position or cash flows.

In December 2004, the FASB issued SFAS 153 "Exchanges of Nonmonetary Assets – an amendment of APB Opinion No. 29." This statement requires that nonmonetary exchanges must be recorded at fair value and the appropriate gain or loss must be recognized so long as the fair value is determinable and the transaction has commercial substance. According to this statement, companies can no longer use the "similar productive assets" concept to account for nonmonetary exchanges at book value with no gain or loss being recognized. FAS 153 will be effective for fiscal periods beginning after June 15, 2005. The adoption of this statement may impact the Company's operating results, financial position or cash flows in future periods if such a nonmonetary exchange occurs.

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment." SFAS 123R revises SFAS 123, "Accounting for Stock-Based Compensation", and focuses on accounting for share-based payments for services by employer to employee. The statement requires companies to expense the fair value of employee stock options and other equity-based compensation at the grant date. The statement does not require a certain type of valuation model and either a binomial or Black-Scholes model may be used. The provisions of SFAS 123R are effective for financial statements for fiscal periods ending after June 15, 2005. The Company is currently evaluating the method of adoption and the impact on the Company's operating results. Future cash flows of the Company will not be impacted by the adoption of this standard. See "Stock Based Compensation" below for further information.

In February 2005, the FASB released for public comment proposed Staff Position FAS 19-a "Accounting for Suspended Well Costs." This proposed staff position would amend FASB Statement No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" and provides guidance about exploratory well costs to companies who use the successful efforts method of accounting. The proposed position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well's economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional disclosures are required to provide information about management's evaluation of capitalized exploratory well costs. In addition, the Staff Position requires the disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. Although this Staff Position is not final and has not been adopted by the company, the company has included the additional disclosures in Note 2. Comments on this proposed FSP are expected by March 7, 2005.

Pipeline Imbalances

Natural gas gathering and pipeline operations normally include imbalance arrangements with the pipeline. The volumes of natural gas due to or from the Company under imbalance arrangements are recorded at actual selling or purchase prices, as the case may be, and are adjusted monthly to reflect market changes. The net value of the natural gas imbalance is included in inventory 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.

Exploratory drilling costs are capitalized when incurred pending the determination of whether a well has found proved reserves. A determination of whether a well has found proved reserves is made shortly after drilling is completed. The determination is based on a process which relies on interpretations of available geologic, geophysic, and engineering data. If a well is determined to be successful the capitalized drilling costs will be reclassified as part of the cost of the well. If a well is determined to be unsuccessful the capitalized drilling costs will be charged to expense in the period the determination is made. If an exploratory well requires a major capital expenditure before production can begin the cost of drilling the exploratory well will continue to be carried as an asset pending determination of whether proved reserves have been found only as long as: i) the well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made and ii) drilling of the additional exploratory wells is under way or firmly planned for the near future. If drilling in the area is not under way or firmly planned, or if the well has not found a commercially producible quantity of reserves, the exploratory well is assumed to be impaired, and its costs are charged to expense.

In the absence of a determination as to whether the reserves that have been found can be classified as proved, the costs of drilling such an exploratory well is not carried as an asset for more than one year following completion of drilling. If, after that year has passed, a determination that proved reserves exist cannot be made, the well is assumed to be impaired, and its costs are charged to expense.

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. In 2003, the Company recorded impairments related to the loss of a reversionary interest in its Kurten field and a field in the East region. These impairments totaled $93.8 million. During 2004, the Company recorded total impairments of $3.5 million. During 2002, the Company recorded total impairments of $2.7 million.

Development costs of proved oil and gas properties, including estimated dismantlement, restoration and abandonment costs, net of estimated salvage values and acquisition costs, are depreciated and depleted on a field basis by the units-of-production method using proved developed and proved reserves, respectively. 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 depreciated on a straight-line basis.

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 at the actual price realized upon the gas sale in accounts payable in the consolidated balance sheet if the Company's excess takes of natural gas exceed its estimated remaining proved developed reserves for these properties. See Note 3 for the Company's wellhead gas imbalances.

Brokered Natural Gas Margin

The revenues and expenses related to brokering natural gas are reported gross as part of Operating Revenues and Operating Expenses. The Company realizes brokered margin as a result of buying and selling natural gas in back-to-back transactions. The Company realized $9.2 million, $9.7 million, and $5.7 million of brokered natural gas margin in 2004, 2003, and 2002, 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. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

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 may include credit balances from outstanding checks in zero balance cash accounts. The credit balance included in accounts payable was $2.7 million at December 31, 2003, which is reflected as an increase in short-term borrowings in financing activities in the Consolidated Statement of Cash Flows. There was no credit balance from outstanding checks in zero balance cash accounts included in accounts payable at December 31, 2004 as sufficient cash was available for offset.

Allowance for Doubtful Accounts

The Company records an allowance for doubtful accounts for receivables that the Company feels may be uncollectible based on the specific identification basis. The allowance for doubtful accounts, which is netted against the accounts receivable line on the balance sheet was $5.3 million and $5.4 million, respectively, as of December 31, 2004 and 2003.

Risk Management Activities

From time to time, the Company enters into derivative contracts, such as natural gas and crude oil price swaps or costless price collars, as a hedging strategy to manage commodity price risk associated with its inventories, production or other contractual commitments. All hedge transactions are subject to the Company's risk management policy which does not permit trading activities. Gains or losses on these hedging activities are generally recognized over the period that its inventories, 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.

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 the hedge is no longer effective, 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.

Stock Based Compensation

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

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

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

	Year Ended December 31,		
(In thousands, except per share amounts)	**2004**	2003	2002
Net Income, as reported	**$ 88,378**	$ 21,132	$ 16,103
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax	**1,571**	1,950	1,605
Pro forma net income	**$ 86,807**	$ 19,182	$ 14,498
Earnings per share:			
Basic – as reported	**$ 2.72**	$ 0.66	$ 0.51
Basic – pro forma	**$ 2.67**	$ 0.60	$ 0.46
Diluted – as reported	**$ 2.69**	$ 0.65	$ 0.50
Diluted – pro forma	**$ 2.64**	$ 0.59	$ 0.45
Share Count	**32,488**	32,050	31,737
Diluted Share Count	**32,893**	32,290	32,076

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.

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

(In thousands, except per share amounts)	Year Ended December 31, 2004	2003	2002
Compensation Expense in Net Income, as reported[1]	**$ 4,043**	$ 1,001	$ 2,326
Weighted Average Value per Option Granted During the Period[2]	**$ 11.31**	$ 6.77	$ 6.23
Assumptions			
Stock Price Volatility	**38.4%**	35.3%	35.8%
Risk Free Rate of Return	**3.3%**	2.5%	3.9%
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 also includes $1.7 million related to the acceleration of stock awards due to the retirement of an executive. Compensation expense in 2004 also includes $2.0 million related to performance shares.*

[2] *Calculated using the Black-Scholes fair value based method*

Cash and Cash Equivalents

The Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. At December 31, 2004, and 2003, the cash and cash equivalents are primarily concentrated in one financial institution. The Company periodically assesses the financial condition of these institutions and believes that any possible credit risk is minimal.

Environmental Matters

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

Use of Estimates

In preparing financial statements, the Company follows generally accepted accounting principles. These principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

2. Properties and Equipment

Properties and equipment are comprised of the following:

(In thousands)	December 31, 2004	2003
Unproved Oil and Gas Properties	**$ 94,795**	$ 86,918
Proved Oil and Gas Properties	**1,646,841**	1,469,751
Gathering and Pipeline Systems	**160,951**	146,909
Land, Building and Improvements	**4,860**	4,758
Other	**31,261**	28,658
	1,938,708	1,736,994
Accumulated Depreciation, Depletion and Amortization	**(944,627)**	(841,039)
	$ 994,081	$ 895,955

As of December 31, 2004, the Company has included disclosures that would be required by the pending FASB Staff Position ("FSP") FAS 19-a, "Accounting for Suspended Well Costs." The Company evaluated all existing capitalized exploratory well costs under the provisions of the pending FSP. The following table reflects the net changes in capitalized exploratory well costs during 2004, 2003 and 2002.

(In thousands)	December 31, 2004	2003	2002
Beginning balance at January 1	**$ 13,277**	$ 3,958	$ 15,548
Additions to capitalized exploratory well costs pending the determination of proved reserves	**49,685**	48,865	26,580
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	**(36,247)**	(12,003)	(21,235)
Capitalized exploratory well costs charged to expense	**(18,605)**	(27,543)	(16,935)
Ending balance at December 31	**$ 8,110**	**$ 13,277**	**$ 3,958**

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling:

(In thousands)	December 31, 2004
Capitalized exploratory well costs that have been capitalized for a period of one year or less	**$ 6,471**
Capitalized exploratory well costs that have been capitalized for a period greater than one year	**—**
Balance at December 31	**$ 6,471**
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**0**

There were no capitalized exploratory well costs at December 31, 2003 and 2002 for wells that have completed drilling without the ability to determine the existence of proved reserves.

At December 31, 2004, the Company had 3 wells that had completed drilling and a determination of whether proved reserves existed could not be made. One well is in the Rocky Mountain area and reached total depth in November 2004. It cannot be completed due to the Bureau of Land Management stipulation which prohibits activity until the summer of 2005. Two wells are in Canada and reached completed drilling in October and December 2004. These wells are awaiting completion or sidetracking which is anticipated to commence by May 2005.

During 2004, the Company recorded an impairment of $3.5 million. The impairment was recorded on a two-well field in south Louisiana and was due to production performance issues related to water encroachment. This impairment charge was recorded due to the capitalized cost of the field exceeding the future undiscounted cash flows. This charge is reflected in the quarterly results and was measured based on discounted cash flows utilizing a discount rate appropriate for risks associated with the related field.

As part of the 2001 Cody acquisition, we acquired an interest in certain oil and gas properties in the Kurten field, as general partner of a partnership and as an operator. We had approximately a 25% interest in the field, including a one percent interest in the partnership. Under the partnership agreement, we had the right to a reversionary working interest that would bring our ultimate interest to 50% upon the limited partner reaching payout. Based on the addition of this reversionary interest, and because the field has over a 40-year reserve life, approximately $91 million was allocated to this field under purchase accounting at the time of the acquisition. Additionally, the limited partner had the sole option to trigger a liquidation of the partnership.

Effective February 13, 2003, liquidation of the partnership commenced at the election of the limited partner. The limited partner was a financial entity and not an industry operator. Their decision to liquidate was based upon their perception that the value of their investment in the partnership had increased due to an increase in underlying commodity prices, primarily oil, since their investment in 1999. We proceeded with the liquidation to avoid having a minority interest in a non-operated water flood field for which the new operator was not designated at the time of liquidation. In connection with the liquidation, an appraisal was required to be obtained to allocate the interest in the partnership assets. Additionally, the Company was required to test the field for recoverability in accordance with SFAS 144. Pursuant to the terms of the partnership agreement and based on the appraised value of the partnership assets it was not possible for us to obtain the reversionary interest as part of the liquidation. Due to the impact of the loss of the reversionary interest on future estimated net cash flows of the Kurten field, the limited partner's decision and our decision to proceed with the liquidation, an impairment review was performed which required an after-tax impairment charge in the first quarter of 2003 of $54.4 million. This impairment charge is reflected in the 2003 Statement of Operations as an operating expense but did not impact our cash flows.

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

In 2002, the Company recorded impairments of $2.7 million. Included in this impairment amount were 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.

3. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

(In thousands)	December 31, 2004	2003
Accounts Receivable		
Trade Accounts	$ 105,378	$ 79,439
Joint Interest Accounts	13,554	13,312
Current Income Tax Receivable	10,796	—
Other Accounts	1,312	81
	131,040	92,832
Allowance for Doubtful Accounts	(5,286)	(5,407)
	$ 125,754	$ 87,425
Other Current Assets		
Derivative Contracts	$ 2,906	$ 1,152
Drilling Advances	6,180	6,443
Prepaid Balances	4,173	4,325
Other Accounts	246	3,086
	$ 13,505	$ 15,006
Accounts Payable		
Trade Accounts	$ 12,808	$ 11,872
Natural Gas Purchases	8,669	5,751
Royalty and Other Owners	35,369	28,001
Capital Costs	26,203	21,964
Taxes Other Than Income	5,634	3,280
Drilling Advances	7,102	5,721
Wellhead Gas Imbalances	1,991	2,085
Other Accounts	7,193	6,269
	$ 104,969	$ 84,943
Accrued Liabilities		
Employee Benefits	$ 10,123	$ 9,105
Taxes Other Than Income	14,191	13,359
Interest Payable	6,569	6,368
Derivative Contracts	38,368	36,582
Other Accounts	1,725	4,344
	$ 70,976	$ 69,758
Other Liabilities		
Postretirement Benefits Other Than Pension	$ 4,717	$ 2,132
Accrued Pension Cost	5,089	2,664
Rabbi Trust Deferred Compensation Plan	4,199	3,568
Derivative Contracts	—	3,051
Accrued Plugging and Abandonment Liability	40,375	36,848
Other	6,649	6,114
	$ 61,029	$ 54,377

4. Inventories

Inventories are comprised of the following:

(In thousands)	December 31, 2004	2003
Natural Gas and Oil in Storage	$ 17,631	$ 15,191
Tubular Goods and Well Equipment	6,387	3,367
Pipeline Imbalances	31	(317)
	$ 24,049	$ 18,241

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

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

On December 10, 2004, the Company amended its Revolving Credit Agreement (Credit Facility) with a group of nine banks. The Credit Facility at year end was $250 million. It can be expanded up to $350 million, either with the existing banks or new banks. This Credit Facility is unsecured. The term of the Credit Facility expires in December 2009. 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 six 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-sixth of the excess during each of the six months.

Interest rates under the Credit Facility are based on Euro-Dollars (LIBOR) or Base Rate (Prime) indications, plus a margin. These associated margins increase if the total indebtedness is 50% or greater, greater than 75% or greater than 90% of the Company's debt limit of $530 million, which can be expanded up to $630 million, as shown below.

	Debt Percentage			
	Lower than 50%	50% or higher but not exceeding 75%	Higher than 75% but not exceeding 90%	Higher than 90%
Euro-Dollar margin	1.000%	1.250%	1.500%	1.750%
Base Rate margin	0.000%	0.000%	0.250%	0.500%

The Company's effective interest rates for the Credit Facility in the years ended December 31, 2004, 2003, and 2002 were 4.2%, 1.9%, and 3.4%, respectively. The Credit Facility provides for a commitment fee on the unused available balance at an annual rate of one-quarter of 1%. The Credit Facility also contains various customary restrictions, which include the following:

(a) 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.

(b) 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.

The Company was in compliance with all covenants at December 31, 2004 and 2003 and during the years then ended.

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 (ERISA) of 1974 and Internal Revenue Code limitations when funding the plan. The measurement date used to measure pension benefit amounts is December 31, 2004.

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

Net periodic pension cost of the Company during the last three years is comprised of the following:

(In thousands)	2004	2003	2002
Qualified			
Current Year Service Cost	$ 1,619	$ 1,481	$ 1,056
Interest Accrued on Pension Obligation	1,697	1,515	1,362
Expected Return on Plan Assets	(1,474)	(999)	(991)
Net Amortization and Deferral	88	88	88
Recognized Loss	383	415	21
Net Periodic Pension Cost	$ 2,313	$ 2,500	$ 1,536
Non-Qualified			
Current Year Service Cost	$ 395	$ 280	$ 78
Interest Accrued on Pension Obligation	381	163	29
Net Amortization	77	77	77
Loss Recognized from Settlement	—	—	963
Recognized Loss	428	187	7
Net Periodic Pension Cost	$ 1,281	$ 707	$ 1,154

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

	2004		2003	
(In thousands)	Qualified	Non-Qualified	Qualified	Non-Qualified
Actuarial Present Value of:				
Accumulated Benefit Obligation	$ 23,181	$ 3,579	$ 21,347	$ 3,171
Projected Benefit Obligation	$ 29,809	$6,257	$ 27,411	$ 6,136
Plan Assets at Fair Value	18,092	—	18,683	—
Projected Benefit Obligation in Excess of Plan Assets	11,717	6,257	8,728	6,136
Unrecognized Net Loss	(9,846)	(4,374)	(7,083)	(5,457)
Unrecognized Prior Service Cost	(248)	(322)	(336)	(399)
Adjustment to Recognize Minimum Liability	3,466	2,018	1,355	2,891
Accrued Pension Cost	$ 5,089	$ 3,579	$ 2,664	$ 3,171

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)	2004	2003	2002
Beginning of Year	$ 33,547	$ 26,042	$ 19,894
Service Cost	2,014	1,761	1,134
Interest Cost	2,078	1,678	1,391
Actuarial Loss	1,798	4,679	5,860
Benefits Paid	(3,371)	(613)	(2,237)
End of Year	$ 36,066	$ 33,547	$ 26,042

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)	**2004**	2003	2002
Beginning of Year	**$ 18,683**	$ 10,279	$ 9,909
Actual Return on Plan Assets	**957**	2,446	(1,280)
Employer Contribution	**2,000**	6,735	4,080
Benefits Paid	**(3,371)**	(613)	(2,237)
Expenses Paid	**(177)**	(164)	(193)
End of Year	**$ 18,092**	$ 18,683	$ 10,279

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)	**2004**	2003	2002
Funded Status	**$ 17,974**	$ 14,864	$15,762
Unrecognized Loss	**(14,220)**	(12,540)	(9,745)
Unrecognized Prior Service Cost	**(570)**	(735)	(899)
Net Amount Recognized	**$ 3,184**	$ 1,589	$ 5,118
Accrued Benefit Liability – Qualified Plan	**$ 5,089**	$ 2,664	$ 7,857
Accrued Benefit Liability – Non-Qualified Plan	**3,579**	3,171	338
Intangible Asset	**(5,484)**	(4,246)	(3,077)
Net Amount Recognized	**$ 3,184**	$ 1,589	$ 5,118

Assumptions used to determine projected postretirement benefit obligations and pension costs are as follows:

	2004	2003	2002
Discount Rate [1]	**5.75%**	6.25%	6.50%
Rate of Increase in Compensation Levels	**4.00%**	4.00%	4.00%
Long-Term Rate of Return on Plan Assets	**8.00%**	8.00%	9.00%
Health Care Cost Trend for Medical Benefits	**10.00%**	8.00%	8.00%

[1] Represents the year end rates used to determine the projected benefit obligation. To compute pension cost in 2004, 2003 and 2002, respectively, the beginning of year discount rates of 6.25%, 6.50% and 7.25%, were used.

The long-term expected rate of return used in 2004 is eight percent. The Company establishes the long-term expected rate of return by developing a forward looking long-term expected rate of return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation.

Estimated future benefit payments under the Company's qualified and non-qualified pension plans are expected to be paid as follows:

(In thousands)	Qualified	Non-Qualified	Total
2005	$ 553	$ 216	$ 769
2006	640	368	1,008
2007	731	262	993
2008	808	316	1,124
2009	963	504	1,467
Years 2010 - 2014	8,332	3,697	12,029

At December 31, 2004 and 2003, the non-qualified pension plan did not have plan assets. The plan assets of the Company's qualified pension plan at December 31, 2004 and 2003, by asset category are as follows:

	2004		2003	
(In thousands)	Amount	Percent	Amount	Percent
Equity securities	$ 13,934	77%	$ 11,722	63%
Debt securities	3,226	18%	3,349	18%
Other [(1)]	932	5%	3,612	19%
Total	$ 18,092	100%	$ 18,683	100%

[(1)] *Primarily consists of cash and cash equivalents.*

The Company's investment strategy for benefit plan assets is to invest in funds to maximize the return over the long-term, subject to an appropriate level of risk. Additionally, the objective is for each class of investments to outperform its representative benchmark over the long term.

The funding levels of the pension plans are in compliance with standards set by applicable law or regulation. In 2004 the Company did not have any required minimum funding obligations; however, it chose to fund $2 million into the plan. In 2005 the Company does not have any required minimum funding obligations. Currently, management has not determined if a discretionary funding will be made in 2005.

Savings Investment Plan

The Company has a Savings Investment Plan (SIP) which is a defined contribution plan. The Company matches a portion of employees' contributions in cash. Participation in the SIP is voluntary and all regular employees of the Company are eligible to participate. The Company charged to expense plan contributions of $1.4 million, $1.4 million, and $1.3 million in 2004, 2003, and 2002, respectively. The Company matches employee contributions dollar-for-dollar on the first 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, 2004, the balance in the Deferred Compensation Plan's rabbi trust was $4.2 million.

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

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

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

Postretirement Benefits Other than Pensions

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits for retired employees, including their spouses, eligible dependents and surviving spouses (retirees). These benefits are commonly called postretirement benefits. Most employees become eligible for these benefits if they meet certain age and service requirements at retirement. The Company was providing postretirement benefits to 251 retirees and their dependants at the end of 2004 and 244 retirees and their dependants at the end of 2003. The measurement date used to measure postretirement benefits other than pensions is December 31, 2004.

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, or $0.8 million per year which is included in the annual expense of the plan. Included in the amortization benefit of the unrecognized transition obligation amount below are the effects of plan amendments during 1996, 2000 and 2004. The remaining unamortized balance is $4.6 million which will be amortized over the next seven years.

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

(In thousands)	**2004**	2003	2002
Service Cost of Benefits Earned During the Year	**$ 671**	$ 265	$ 215
Interest Cost on the Accumulated Postretirement Benefit Obligation	**784**	385	381
Amortization Benefit of the Unrecognized Gain	**(59)**	(155)	(267)
Amortization of Prior Service Cost	**1,211**	—	—
Amortization Benefit of the Unrecognized Transition Obligation	**662**	662	662
Total Postretirement Benefit Cost	**$ 3,269**	$ 1,157	$ 991

The health care cost trend rate used to measure the expected cost from 2000 to 2003 for medical benefits to retirees was 8%. Provisions of the plan should prevent significant future increases in employer cost after 2000. During the year ended December 31, 2004, the plan was amended and the limit, or cap, on the employer subsidy for medical and prescription drug coverage provided to participants age 65 and older was removed. In addition, certain other modifications to the plan were made to limit prescription drug coverage (for participants not age 65 and older) and increase the plan deductibles and reimbursements by retirees. The company subsidy for all retiree medical and prescription drug benefits for all other participants, beginning January 1, 2006, is limited to an aggregate annual amount not to exceed $648,000. This limit will increase by 3.5% annually thereafter.

The health care cost trend rate used at December 31, 2004 was 10%. The rate to which the cost trend rate is assumed to decline (the ultimate trend rate) is 5% as of December 31, 2004. The year that this ultimate trend rate will be reached is 2009.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In thousands)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost	$ 146	$ (163)
Effect on postretirement benefit obligation	1,661	(2,025)

The funded status of the Company's postretirement benefit obligation at December 31, 2004, and 2003 is comprised of the following:

(In thousands)	**2004**	2003
Plan Assets at Fair Value	**$ —**	$ —
Accumulated Postretirement Benefits Other Than Pensions	**14,101**	6,181
Unrecognized Cumulative Net Gain	**814**	1,736
Unrecognized Prior Service Cost	**(5,691)**	—
Unrecognized Transition Obligation	**(4,631)**	(5,293)
Accrued Postretirement Benefit Liability	**$ 4,593**	$ 2,624

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

(In thousands)	2004	2003	2002
Beginning of Year	$ 6,181	$ 6,185	$ 5,507
Service Cost	671	265	215
Interest Cost	784	386	381
Amendments	6,901	—	—
Actuarial Loss	864	221	912
Benefits Paid	(1,300)	(876)	(830)
End of Year	$ 14,101	$ 6,181	$ 6,185

Estimated future benefit payments are expected to be paid as follows:

(In thousands)	
2005	$ 1,034
2006	653
2007	688
2008	706
2009	735
Years 2010-2014	4,479

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduces a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to certain Medicare benefits. In accordance with FSP No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", any measures of the accumulated plan benefit obligation or net periodic postretirement benefit cost in the financial statements or accompanying notes do not reflect the effects of the Act on the Company's plan. As the Company has amended the postretirement benefit plan to exclude prescription drug benefits to participants age 65 and older effective January 1, 2006, management believes this FSP will not have an impact on operating results, financial position or cash flows of the Company.

7. Income Taxes

Income tax expense (benefit) is summarized as follows:

	Year Ended December 31,		
(In thousands)	2004	2003	2002
Current			
Federal	$ 14,767	$ 22,826	$ (1,158)
State	3,710	2,075	869
Total	18,477	24,901	(289)
Deferred			
Federal	31,779	(8,549)	7,931
State	(10)	(1,289)	32
Total	31,769	(9,838)	7,963
Total Income Tax Expense	$ 50,246	$ 15,063	$ 7,674

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, 2004	2003	2002
Statutory Federal Income Tax Rate	**35%**	35%	35%
Computed "Expected" Federal Income Tax	**$ 48,518**	$15,065	$ 8,322
State Income Tax, Net of Federal Income Tax Benefit	**4,353**	1,334	737
Other, Net	**(2,625)**[1]	(1,336)[2]	(1,385)[3]
Total Income Tax Expense	**$ 50,246**	$15,063	$ 7,674

(1) *Other, Net includes credit adjustments of $1.6 million related to the recognition of benefit for federal statutory depletion in excess of basis, $0.9 million related to the recognition of benefit for state statutory depletion in excess of basis, and other permanent items.*

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

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

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

(In thousands)	2004	2003
Deferred Tax Liabilities		
Property, Plant and Equipment	**$ 246,962**	$ 208,955
Items Accrued for Financial Reporting Purposes	**1,358**	1,826
	248,320	210,781
Deferred Tax Assets		
Net Operating Loss Carryforwards	**2,045**	725
Items Accrued for Financial Reporting Purposes	**21,290**	15,893
Other Comprehensive Income	**12,865**	14,237
	36,200	30,855
Net Deferred Tax Liabilities	**$ 212,120**	$ 179,926

As of December 31, 2004, the Company had a net operating loss carryforward of $39.5 million for state income tax reporting purposes, the majority of which will expire between 2011 and 2024 and none available for regular federal income tax purposes. It is expected that these deferred tax benefits will be utilized prior to their expiration.

8. Commitments and Contingencies

Lease Commitments

The Company leases certain transportation vehicles, warehouse facilities, office space, and machinery and equipment under cancelable and non-cancelable leases. The lease for the Company's office in Houston runs for approximately five more years. Most of the Company's leases expire within five years and may be renewed. Rent expense under such arrangements totaled $8.7 million, $8.5 million, and $8.8 million for the years ended December 31, 2004, 2003, and 2002, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2004 are as follows:

(In thousands)	
2005	$ 4,889
2006	4,542
2007	4,340
2008	2,063
2009	784
Thereafter	382
	$ 17,000

Contingencies

The Company is a defendant in 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. While the outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the Company's consolidated financial position. Operating results and cash flow, however, could be significantly impacted in the reporting periods in which such matters are resolved.

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

In January 2002, 13 overriding royalty owners sued the Company in Wyoming federal district court. The plaintiffs in the federal case have made the same general claims pertaining to deductions from their overriding royalty as the plaintiffs in the Wyoming state court case but have not asked for class certification.

The federal district court judge certified two questions of state law for decision by the Wyoming State Supreme Court, which recently answered both questions. The Wyoming Supreme Court ruled that certain deductions taken by the Company from the plaintiffs were not proper and that the statutes of limitations advanced by the Company are discovery statutes and accordingly do not begin to run until the plaintiffs knew, or had reason to know, of the violation. The Company believes it has properly reported to the plaintiffs, and that if it did not, the plaintiffs knew or should have known the reporting was improper and the nature of the deductions, thus triggering the statute of limitations. The Company still intends to raise defenses to the alleged failure to report claims. There is also a dispute as to how the interest should be calculated.

The federal judge refused to certify a question relating to the issue of the proper calculation of damages for failure to provide certain information required by statute on overriding royalty owner check stubs that had been decided adversely to our position in a state district court letter decision in a separate case. After the federal judge's refusal to certify this issue, the plaintiffs reduced the damages they were claiming. Based upon recent communication from the plaintiffs they are now claiming $26.2 million in total damages which consists of $20.3 million for alleged violations of the check stub reporting statute and $5.9 million for all other damages.

In the opinion of our outside counsel, Brown, Drew & Massey, LLP, the likelihood of the plaintiffs recovering $20.3 million for the check stub reporting statute is remote. However, a reserve that management believes is adequate to provide for the check stub reporting statute and all other damages has been established based on management's estimate at this time of the probable outcome of this case.

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 it had taken improper deductions from the royalty and failed to properly inform the plaintiffs and other similarly situated persons of deductions taken from the royalty. The plaintiffs have also claimed that they are entitled to a 1/8th royalty share of the gas sales contract settlement that the Company reached with Columbia Gas Transmission Corporation in the 1995 Columbia Gas Transmission Corporation bankruptcy proceeding.

Discovery and pleadings necessary to place the class certification issue before the state court have been ongoing. A hearing on the plaintiffs' motion for class certification was held on October 20, 2003, and proposed findings of fact and conclusions of law were submitted to the court on December 5, 2003. A status conference was held with the court and the court advised it intends to issue a ruling on the class certification motion. The court was expected to rule by December 2004, and we are still awaiting a decision. Discovery is proceeding on the claims pending the ruling on the class certification motion. Discovery is to be completed by April 1, 2005, and the trial is currently scheduled for August 15, 2005. If a class is certified it is expected this trial date will be continued to a later date.

The investigation into this claim continues and it is in the discovery phase. The Company is vigorously defending the case. It has a reserve that management believes is adequate based on its estimate of the probable outcome of this case.

Texas Title Litigation. On January 6, 2003, the Company was served with Plaintiffs' Second Amended Original Petition in Romeo Longoria, et al. v. Exxon Mobil Corporation, et al. in the 79th Judicial District Court of Brooks County, Texas. Plaintiffs filed their First Supplemental Original Petition on March 17, 2004 and their Second Supplemental Petition on November 12, 2004. The significant change in the second Supplemental Petition is that plaintiffs appear to limit their claim to the mineral estate, rather than making claims to both the surface and mineral estate. The plaintiffs allege that they are the rightful owners of a one-half undivided mineral interest in and to certain lands in Brooks County, Texas. As Cody Energy, LLC, the Company acquired certain leases and wells from Wynn-Crosby 1996, Ltd. in 1997 and 1998 and the Company subsequently acquired a 320 acre lease from Hector and Gloria Lopez in 2001. The plaintiffs allege that they are entitled to be declared the rightful owners of an undivided interest in minerals and all improvements on the lands on which the Company acquired these leases. The plaintiffs also assert claims for trespass to try title, action to remove a cloud on the title, failure to properly account for royalty, fraud, trespass, conversion, all for unspecified actual and exemplary damages. The original trial date of May 19, 2003 was cancelled and a new trial date has not been set. The Company has not had the opportunity to conduct discovery in this matter. The Company estimates that production revenue from this field since its predecessor, Cody Energy, LLC, acquired title and since the Company acquired its lease is approximately $14.9 million. The carrying value of this property is approximately $34 million. Co-defendants Shell Oil Company and Shell Western E&P filed a motion for summary judgment seeking dismissal of plaintiffs' causes of action on multiple grounds. The original plaintiffs' attorneys asked permission from the Court to withdraw from the representation. The Court granted that request, and new attorneys for some, but not all of the plaintiffs have recently entered the case. The motion for summary judgment was reset and a hearing was held in December of 2003. The Company joined in the motion. After a second hearing, the Court denied the motion for summary judgment. The defendants have moved to add parties whose title interests are being challenged by the plaintiffs, and who are therefore necessary to the case, or in the alternative, abate the proceeding until the plaintiffs join all parties whose interests may be affected by plaintiffs' claims.

Although the investigation into this claim is in its early stages, the Company intends to vigorously defend the case. Should the Company receive an adverse ruling in this case, an impairment review would be assessed to ensure the carrying value of the property is recoverable. Management cannot currently determine the likelihood of an unfavorable outcome or range of any potential loss should the outcome be unfavorable. Accordingly, there has been no reserve established for this matter.

Raymondville Area. In April 2004, the Company's wholly owned subsidiary, Cody Energy, LLC, filed suit in Willacy County, Texas against certain of its co-working interest owners in the Raymondville Area, located in Kenedy and Willacy Counties. In early 2003, Cody had proposed a new prospect to certain of these co-working interest owners located within jointly owned oil and gas leases. Some of the co-working interest owners elected to participate and some did not. The initial well was successful and subsequent wells have been drilled to exploit the discovery made in the first well.

In December 2003, certain of the co-working interest owners who elected not to participate in the initial well notified Cody that they believed that they had the right to participate in subsequent wells. Cody contends that, under the terms of the agreements between the parties, the co-working interest owners that elected not to participate in the initial well in the prospect were required to assign their interest in the proposed prospect to those who elected to participate. Alternatively, Cody contends that such owners lost their right to participate in subsequent wells within a 1,200 foot radius of the initial well.

The defendants have filed a counter claim against the Company and one of the defendants has filed a lien against Cody's interest in the leases in the Raymondville Area. Cody contends that this lien is improper and has sought damages for its filing. Cody is vigorously prosecuting this case which is in its early stage of discovery. No trial date has been set by the court.

Certain of the defendants filed a Motion for Partial Summary Judgment contending that they did not have adequate notice of the prospect proposal. Cody is contesting this Motion. In addition, in late December 2004, Cody filed a Motion for Final Summary Judgment asking the court to find that, under the terms of the agreements, Cody and the participating working interest owners are entitled to an assignment of the interests of the co-working interest owners who elected not to participate in the prospect. No hearing date has been set by the court.

Management cannot currently determine the likelihood of an unfavorable outcome or range of any potential loss should the outcome be unfavorable. Accordingly, there has been no reserve established for this matter.

Commitment and Contingency Reserves. The Company has established reserves for certain legal proceedings. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur approximately $11.1 million of additional loss with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

While the outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the consolidated financial position of the Company. Operating results and cash flow, however, could be significantly impacted in the reporting periods in which such matters are resolved.

9. Cash Flow Information

Cash paid for interest and income taxes is as follows:

	Year Ended December 31,		
(In thousands)	**2004**	2003	2002
Interest	**$ 16,415**	$ 18,298	$ 25,112
Income Taxes	**29,861**	19,267	266

The Company recorded benefits of $2.6 million, $1.0 million and $0.4 million for the years ended December 31, 2004, 2003 and 2002, respectively, for tax deductions taken due to employee stock option exercises and restricted stock grant vesting.

10. Capital Stock

Incentive Plans

On April 29, 2004, the 2004 Incentive Plan was approved by the shareholders. Under the 2004 Incentive Plan, incentive and non-statutory stock options, stock appreciation rights (SARs), stock awards, cash awards and performance awards may be granted to key employees, consultants and officers of the Company. Non-employee directors of the Company may be granted discretionary awards under the 2004 Incentive Plan consisting of stock options or stock awards, in addition to the automatic award of an option to purchase 10,000 shares of Common Stock on the date the non-employee directors first join the board of directors. A total of 1,700,000 shares of Common Stock may be issued under the 2004 Incentive Plan. In addition, shares remaining available for award under the 1994 Long-Term Incentive Plan and the Second Amended and Restated 1994 Non-Employee Director Stock Option Plan (herein "Prior Plans") were subsumed into the 2004 Incentive Plan (228,398 shares on April 29, 2004). Under the 2004 Incentive Plan, no more than 600,000 shares may be used for stock awards that are not subject to the achievement of performance based goals, and no more than 1,000,000 shares may be issued pursuant to incentive stock options. Awards outstanding under the Prior Plans will remain outstanding in accordance with their original terms and conditions.

During 2004, the Board of Directors granted a series of 168,500 performance share awards to certain executives and key employees of the Company. These awards are earned based on the comparative performance of the Company's Common Stock measured against sixteen other companies in the Company's peer group over a three year vesting period ending on December 31, 2006. Depending on the Company's performance, employees may earn up to 100% of the award in Common Stock, and an additional 100% of the award in cash. The performance shares qualify for variable accounting, and accordingly, are recorded at their fair value with compensation expense recognized over the performance period.

During 2004, the Company granted 7,000 restricted stock units to various Company Directors. These units immediately vest and will be paid out whenever the Director ceases to be a Director of the Company. For all restricted stock units, the Company recognized compensation expense equal to the market value of the Company's Common Stock on the grant date of the respective awards.

Information regarding stock options under the Company's 2004 Incentive Plan and the Prior Plans is summarized below:

	December 31,		
	2004	2003	2002
Shares Under Option at Beginning of Period	**1,349,501**	1,287,829	1,081,621
Granted	**24,500**	467,000	429,300
Exercised	**529,183**	345,386	181,027
Surrendered or Expired	**33,129**	59,942	42,065
Shares Under Option at End of Period	**811,689**	1,349,501	1,287,829
Options Exercisable at End of Period	**377,329**	511,719	570,406

For each of the three most recent years, the price range for outstanding options was $17.44 to $34.98 per share. The following tables provide more information about the options by exercise price and year.

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

	December 31,		
	2004	2003	2002
Options Outstanding			
Number of Options	**229,963**	444,668	737,385
Weighted Average Exercise Price	**$ 19.28**	$ 19.22	$ 18.97
Weighted Average Contractual Term *(In years)*	**2.0**	2.6	3.0
Options Exercisable			
Number of Options	**122,491**	204,229	301,277
Weighted Average Exercise Price	**$ 19.29**	$ 19.04	$ 18.39

Options with exercise prices between $20.01 and $34.98 per share:

	December 31,		
	2004	2003	2002
Options Outstanding			
Number of Options	**581,726**	904,833	550,444
Weighted Average Exercise Price	**$ 24.24**	$ 24.69	$ 25.81
Weighted Average Contractual Term (*In years*)	**2.7**	3.4	3.0
Options Exercisable			
Number of Options	**254,838**	307,490	269,129
Weighted Average Exercise Price	**$ 24.44**	$ 26.42	$ 25.39

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. During the year ended December 31, 2004, the Company repurchased 405,100 shares for a total cost of approximately $15.6 million. The repurchased shares are held as treasury stock. Since the authorization date, the Company has repurchased 707,700 shares, or 35% of the total shares authorized for repurchase, for a total cost of approximately $20 million. In 2004, the stock repurchase plan was funded from cash flow from operations. 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, 2004 there were no shares of Junior Preferred Stock issued or outstanding.

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

11. Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the consolidated balance sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value. The Company uses available marketing data and valuation methodologies to estimate the 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, 2004		December 31, 2003	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Debt				
7.19% Notes	**$ 80,000**	**$ 87,770**	$ 100,000	$113,673
7.26% Notes	**75,000**	**85,849**	75,000	87,345
7.36% Notes	**75,000**	**87,111**	75,000	87,770
7.46% Notes	**20,000**	**23,804**	20,000	24,214
Credit Facility	**—**	**—**	—	—
	$250,000	**$284,534**	$ 270,000	$313,002

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

Derivative Instruments and Hedging Activity

The Company periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on natural gas and crude oil production. At December 31, 2004, the Company had 15 cash flow hedges open: 7 natural gas price collar arrangements, one crude oil collar arrangement and 7 natural gas price swap arrangements. Additionally, the Company had two crude oil financial instruments open at December 31, 2004, that did not qualify for hedge accounting under SFAS 133. At December 31, 2004, a $28.8 million ($17.8 million net of tax) unrealized loss was recorded to Other Comprehensive Income, along with a $38.4 million derivative liability and a $2.9 million derivative receivable. The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Other Comprehensive Income. The ineffective portion, if any, of the change in the fair value of derivatives designated as hedges, and the changes in fair value of all other derivatives is recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate revenue, as appropriate.

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

	Year Ended December 31,					
	2004		2003		2002	
(In thousands)	**Realized**	**Unrealized**	Realized	Unrealized	Realized	Unrealized
Operating Revenues - *Increase / (Decrease) to Revenue*						
Natural Gas Production	**$ (55,008)**	**$ 914**	$ (48,829)	$ (1,468)	$ (574)	$ (1,683)
Crude Oil	**(17,908)**	**(2,917)**	(3,963)	(1,879)	(5,202)	(693)

Assuming no change in commodity prices, after December 31, 2004 the Company would reclassify to earnings, over the next 12 months, $17.8 million in after-tax expenditures associated with commodity derivatives. This reclassification represents the net liability associated with open positions currently not reflected in earnings at December 31, 2004 related to anticipated 2005 production.

Hedges on Production - Swaps. From time to time, the Company enters into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of 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 Company's Revolving Credit Agreement, the aggregate level of commodity hedging must not exceed 100% of the anticipated future equivalent production during the period covered by these cash flow hedges. During 2004, natural gas price swaps covered 29,617 Mmcf, or 41% of the Company's gas production, fixing the sales price of this gas at an average of $5.04 per Mcf.

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

	Natural Gas Price Swaps		
Contract Period	Volume in Mmcf	Weighted Average Contract Price	Unrealized Gain / (Loss) *(In thousands)*
As of December 31, 2004			
Natural Gas Price Swaps on Production in:			
First Quarter 2005	5,069	$ 5.14	
Second Quarter 2005	5,125	5.14	
Third Quarter 2005	5,181	5.14	
Fourth Quarter 2005	5,181	5.14	
Full Year 2005	**20,556**	**$ 5.14**	**$ (27,897)**

From time to time the Company enters into natural gas and crude oil derivative arrangements that do not qualify for hedge accounting under SFAS 133. These financial instruments are recorded at fair value at the balance sheet date. At December 31, 2004, the Company had two open crude oil swap arrangements with an unrealized net loss of $5.5 million recognized in Operating Revenues.

Hedges on Production - Options. From time to time, the Company enters into natural gas and crude oil collar agreements with counterparties to hedge price risk associated with a portion of its production. These cash flow hedges are not held for trading purposes. Under the collar arrangements, if the index price rises above the ceiling price, the Company pays the counterparty. If the index falls below the floor price, the counterparty pays the Company. During 2004, natural gas price collars covered 22,954 Mmcf of the Company's gas production, or 32% of the Company's gas production with a weighted average floor of $4.78 per Mcf and a weighted average ceiling of $6.06 per Mcf.

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

	Natural Gas Price Collars		
Contract Period	Volume in Mmcf	Weighted Average Ceiling / Floor	Unrealized Gain / (Loss) *(In thousands)*
As of December 31, 2004			
First Quarter 2005	4,982	$ 9.09/$6.16	
Second Quarter 2005	3,367	8.38/5.30	
Third Quarter 2005	3,404	8.38/5.30	
Fourth Quarter 2005	3,404	8.38/5.30	
Full Year 2005	**15,157**	**$ 8.61/$5.59**	**$ (2,500)**

At December 31, 2004, we had one open crude oil price collar contract covering our 2005 production as follows:

	Crude Oil Price Collar		
Contract Period	Volume in Mbbl	Weighted Average Ceiling / Floor	Unrealized Gain / (Loss) *(In thousands)*
As of December 31, 2004			
First Quarter 2005	90	$50.50/$40.00	
Second Quarter 2005	91	50.50/40.00	
Third Quarter 2005	92	50.50/40.00	
Fourth Quarter 2005	92	50.50/40.00	
Full Year 2005	**365**	**$50.50/$40.00**	**$ 454**

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

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 2004, approximately 11% of the Company's total sales were made to one customer. In 2003 and 2002, approximately 11% and 14%, respectively, of our total sales were made to one customer. In 2002, this customer operated certain properties in which we have interests in the Gulf Coast and purchased all of the production from these wells. This customer would resell the natural gas and oil to third parties with whom we would deal directly if the customer either ceased to exist or stopped buying our portion of the production.

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

Effective January 1, 2003 the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations." SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method over the assets useful life. The adoption of SFAS 143 resulted in an increase of total liabilities because additional retirement obligations are required to be recognized, an increase in the recognized cost of assets because the retirement costs are added to the carrying amount of the long-lived asset and an increase in operating expense because of the accretion of the retirement obligation and additional depreciation and depletion. The majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells. However, liabilities will also be recorded for meter stations, pipelines, processing plants and compressors. At December 31, 2004 there are no assets legally restricted for purposes of settling asset retirement obligations. The Company recorded a net-of-tax charge for the cumulative effect of change in accounting principle loss, in January of 2003, of approximately $6.8 million ($11.0 million before tax) and recorded a retirement obligation of approximately $35.2 million. There will be no impact on the Company's cash flows as a result of adopting SFAS 143.

Additional retirement obligations increase the liability associated with new oil and gas wells and other facilities as these obligations are incurred. Accretion expense for the year ended December 31, 2004 was $1.7 million. Accretion expense for the year ended December 31, 2003 was $2.1 million.

The following table reflects the changes of the asset retirement obligations during the current period.

(In thousands)	
Carrying amount of asset retirement obligations at December 31, 2003	$ 36,848
Liabilities added during the current period	2,316
Liabilities settled during the current period	(520)
Current period accretion expense	1,731
Revisions to estimated cash flows	—
Carrying amount of asset retirement obligations at December 31, 2004	$ 40,375

If SFAS 143 had been adopted on January 1, 2002, pro forma net income would have been approximately $15.1 million, pro forma basic earnings per share would have been $0.48 and pro forma diluted earnings per share would have been $0.47. These pro forma figures are unaudited.

13. 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 East and Rocky Mountains properties. The tax credit wells were re-purchased in December 2002 and no tax credits were generated in 2003 or 2004 as the credits expired in 2002. Revenue from these monetized credits was $2.0 million in 2002. The production, revenues, expenses and proved reserves for these properties was reported by the Company as Other Revenue until the credits were repurchased in December 2002. In this repurchase transaction, the Company acquired 26 Bcfe for $7 million, or $0.27 per Mcfe. The effective date of the repurchase was December 31, 2002.

14. Earnings per Common Share

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

The following is a calculation of basic and diluted weighted average shares outstanding for the year ended December 31, 2004, 2003 and 2002:

	December 31,		
	2004	2003	2002
Shares - Basic	**32,488,336**	32,049,664	31,736,975
Dilution effect of stock options and awards at end of period	**404,198**	240,621	338,972
Shares - Diluted	**32,892,534**	32,290,285	32,075,947
Stock awards and shares excluded from diluted earnings per share due to the anti-dilutive effect	**—**	965,777	1,174,507

15. Subsequent Event-Stock Split

On February 28, 2005, the Company announced that the Board of Directors had declared a 3-for-2 split on the Company's Common Stock in the form of a stock distribution. The stock dividend will be distributed on March 31, 2005 to shareholders of record on March 18, 2005. In lieu of issuing fractional shares, the Company will pay cash based on the closing price of the Common stock on the record date. The pro forma effect on the December 31, 2004 balance sheet is to reduce Additional Paid-in-Capital by $1.6 million and increase Common Stock by $1.6 million. Common shares outstanding, giving retroactive effect to the stock split at December 31, 2004 and 2003 would have been 48.6 million and 48.4 million, respectively. Pro forma earnings per share, giving retrospective effect to the stock split is as follows:

	December 31,		
	2004	2003	2002
Basic Earnings per Share – as reported (pre-stock split)	**$ 2.72**	$ 0.66	$ 0.51
Basic Earnings per Share – pro forma (post-stock split)	**1.81**	0.44	0.34
Diluted Earnings per Share – as reported (pre-stock split)	**2.69**	0.65	0.50
Diluted Earnings per Share – pro forma (post-stock split)	**1.79**	0.43	0.33

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, 2004, 2003, and 2002 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, 2005, 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, 2004, 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)	**2004**	2003	2002
Proved Reserves			
Beginning of Year	**1,069,484**	1,060,959	1,036,004
Revisions of Prior Estimates	**(7,850)**	(6,122)	14,405
Extensions, Discoveries and Other Additions	**140,986**	105,497	64,945
Production	**(72,833)**	(71,906)	(73,670)
Purchases of Reserves in Place	**5,384**	1,590	26,262
Sales of Reserves in Place	**(1,090)**	(20,534)	(6,987)
End of Year	**1,134,081**	1,069,484	1,060,959
Proved Developed Reserves	**857,834**	812,280	819,412
Percentage of Reserves Developed	**75.6%**	76.0%	77.2%

	Liquids		
	December 31,		
(Thousands of barrels)	**2004**	2003	2002
Proved Reserves			
Beginning of Year	**12,103**	18,393	19,684
Revisions of Prior Estimates	**185**	307	1,871
Extensions, Discoveries and Other Additions	**1,074**	1,723	851
Production	**(2,002)**	(2,846)	(2,909)
Purchases of Reserves in Place	**24**	—	261
Sales of Reserves in Place	**—**	(5,474)	(1,365)
End of Year	**11,384**	12,103	18,393
Proved Developed Reserves	**8,652**	9,405	13,267
Percentage of Reserves Developed	**76.0%**	77.7%	72.1%

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.

	December 31,		
(In thousands)	**2004**	2003	2002
Aggregate Capitalized Costs Relating to Oil and Gas Producing Activities	**$ 1,933,848**	$ 1,732,236	$ 1,704,746
Aggregate Accumulated Depreciation, Depletion and Amortization	**940,447**	837,060	750,857

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

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

	Year Ended December 31,		
(In thousands)	**2004**	2003	2002
Property Acquisition Costs, Proved	**$ 3,953**	$ 1,524	$ 8,799
Property Acquisition Costs, Unproved	**18,250**	14,056	4,869
Exploration and Extension Well Costs(1)	**85,415**	83,147	52,012
Development Costs	**136,311**	77,006	55,165
Total Costs	**$ 243,929**	$ 175,733	$ 120,845

(1) *Includes administrative exploration costs of $11,354, $10,582, and $8,942 for the years ended December 31, 2004, 2003, and 2002, respectively.*

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)	**2004**	2003	2002
Operating Revenues	**$ 439,988**	$ 404,503	$ 280,379
Costs and Expenses			
Production	**84,015**	77,315	63,823
Other Operating	**27,787**	20,090	21,731
Exploration(1)	**48,130**	58,119	40,167
Depreciation, Depletion and Amortization	**114,906**	195,659	102,086
Total Costs and Expenses	**274,838**	351,183	227,807
Income Before Income Taxes	**165,150**	53,320	52,572
Provision for Income Taxes	**60,361**	18,662	18,400
Results of Operations	**$ 104,789**	$ 34,658	$ 34,172

(1) *Includes administrative exploration costs of $11,354, $10,582, and $8,942 for the years ended December 31, 2004, 2003, and 2002, respectively.*

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 to the estimated future production of year end proved reserves.

The average prices related to proved reserves at December 31, 2004, 2003, and 2002 for natural gas ($ per Mcf) were $6.26, $5.96, and $4.41, respectively, and for oil ($ per Bbl) were $41.24, $30.94, and $30.39, 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:

	Year Ended December 31,		
(In thousands)	**2004**	2003	2002
Future Cash Inflows	**$ 7,561,728**	$6,742,214	$5,236,349
Future Production Costs	**(1,577,787)**	(1,390,398)	(1,137,615)
Future Development Costs	**(396,431)**	(310,923)	(284,165)
Future Income Tax Expenses	**(2,009,644)**	(1,800,519)	(1,195,082)
Future Net Cash Flows	**3,577,866**	3,240,374	2,619,487
10% Annual Discount for Estimated Timing of Cash Flows	**(1,997,509)**	(1,760,966)	(1,364,134)
Standardized Measure of Discounted Future Net Cash Flows	**$ 1,580,357**	$1,479,408	$1,255,353

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:

	Year Ended December 31,		
(In thousands)	**2004**	2003	2002
Beginning of Year	**$ 1,479,408**	$1,255,353	$ 766,026
Discoveries and Extensions, Net of Related Future Costs	**321,026**	235,079	112,269
Net Changes in Prices and Production Costs	**(17,976)**	475,026	703,874
Accretion of Discount	**219,604**	171,590	95,110
Revisions of Previous Quantity Estimates, Timing and Other	**(46,115)**	(35,691)	51,944
Development Costs Incurred	**32,940**	27,529	20,516
Sales and Transfers, Net of Production Costs	**(357,939)**	(330,800)	(216,555)
Net Purchases (Sales) of Reserves in Place	**10,853**	(62,596)	(2,357)
Net Change in Income Taxes	**(61,444)**	(256,082)	(275,474)
End of Year	**$ 1,580,357**	$1,479,408	$1,255,353

SELECTED DATA (UNAUDITED)

QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

(In thousands, except per share amounts)	First	Second	Third	Fourth	Total
2004					
Operating Revenues	**$136,604**	**$119,742**	**$119,423**	**$154,639**	**$530,408**
Impairment of Oil and Gas Properties	**—**	**—**	**3,458**	**—**	**3,458**
Operating Income	**36,090**	**36,439**	**34,278**	**53,846**	**160,653**
Income Before Cumulative Effect of Accounting Change	**19,011**	**19,318**	**17,822**	**32,227**	**88,378**
Net Income	**19,011**	**19,318**	**17,822**	**32,227**	**88,378**
Basic Earnings per Share - Before Accounting Change	**$ 0.59**	**$ 0.59**	**$ 0.55**	**$ 0.99**	**$ 2.72**
Diluted Earnings per Share - Before Accounting Change	**$ 0.58**	**$ 0.59**	**$ 0.54**	**$ 0.98**	**$ 2.69**
Basic Earnings per Share	**$ 0.59**	**$ 0.59**	**$ 0.55**	**$ 0.99**	**$ 2.72**
Diluted Earnings per Share	**$ 0.58**	**$ 0.59**	**$ 0.54**	**$ 0.98**	**$ 2.69**
2003					
Operating Revenues	$ 135,916	$ 126,756	$ 125,471	$ 121,248	$ 509,391
Impairment of Oil and Gas Properties	87,926	—	5,870	—	93,796
Operating Income (Loss)	(46,691)	34,850	43,630	34,798	66,587
Income (Loss) Before Cumulative Effect of Accounting Change	(32,376)	17,904	23,220	19,231	27,979
Net Income (Loss)[1]	(39,223)	17,904	23,220	19,231	21,132
Basic Earnings (Loss) per Share - Before Accounting Change[1]	$ (1.02)	$ 0.56	$ 0.73	$ 0.60	$ 0.87
Diluted Earnings (Loss) per Share - Before Accounting Change[1]	$ (1.02)	$ 0.55	$ 0.73	$ 0.60	$ 0.87
Basic Earnings (Loss) per Share[1]	$ (1.23)	$ 0.56	$ 0.73	$ 0.60	$ 0.66
Diluted Earnings (Loss) per Share[1]	$ (1.23)	$ 0.55	$ 0.73	$ 0.60	$ 0.65

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

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

None.

ITEM 9A. Controls and Procedures

CONCLUSION REGARDING THE EFFECTIVENESS OF DISCLOSURE CONTROLS AND PROCEDURES AND CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

At of the end of December 31, 2004, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the "Exchange Act"). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission's rules and forms, of information required to be disclosed by the issuer in the reports that it files or submits under the Exchange Act.

There were no significant changes in the Company's internal control over financial reporting that occurred during the fourth quarter that has materially affected, or is reasonably likely to materially effect, the Company's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Cabot Oil & Gas Corporation is responsible for establishing and maintaining adequate internal control over financial reporting. Cabot Oil & Gas Corporation's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Cabot Oil & Gas Corporation's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework. Based on our assessment we have concluded that, as of December 31, 2004, the Company's internal control over financial reporting is effective based on those criteria.

Cabot Oil & Gas Corporation's independent registered public accounting firm has audited management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 as stated in their report which appears herein. This report appears on page 54.

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors and Executive Officers of the Registrant

The information under the caption "Election of Directors", "Audit Committee" and "Code of Business Conduct" in the Company's definitive Proxy Statement in connection with the 2005 annual stockholders' meeting is incorporated by reference.

ITEM 11. Executive Compensation

The information under the caption "Executive Compensation" in the Company's definitive Proxy Statement in connection with the 2005 annual stockholders' meeting is incorporated by reference.

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

The information under the captions "Beneficial Ownership of Over Five Percent of Common Stock", "Beneficial Ownership of Directors and Executive Officers", and "Equity Compensation Plan Information" in the Company's definitive Proxy Statement in connection with the 2005 annual stockholders' meeting is incorporated by reference.

ITEM 13. Certain Relationships and Related Transactions

None.

ITEM 14. Principal Accounting Fees and Services

The information under the caption "Fees Billed by Independent Registered Public Accounting Firm for Services in 2003 and 2002" in the Company's definitive Proxy Statement in connection with the 2005 annual stockholders' meeting is incorporated by reference.

PART IV

ITEM 15. Exhibits, and Financial Statement Schedules

A. INDEX

1. Consolidated Financial Statements

See Index on page 54.

2. Financial Statement Schedules

None.

3. Exhibits

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

Exhibit Number	Description
3.1	Certificate of Incorporation of the Company (Registration Statement No. 33-32553).
3.2	Amended and Restated Bylaws of the Company amended September 6, 2001 (Form 10-K for 2001).
3.3	Certificate of Amendment of Certificate of Incorporation (Form 8-K for July 2, 2002).
3.4	Certificate of Increase of Shares Designated Series A Junior Participating Preferred Stock (Form 8-K for July 2, 2002).
4.1	Form of Certificate of Common Stock of the Company (Registration Statement No. 33-32553).
4.2	Certificate of Designation for Series A Junior Participating Preferred Stock (Form 10-K for 1994).
4.3	Rights Agreement dated as of March 28, 1991, between the Company and The First National Bank of Boston, as Rights Agent, which includes as Exhibit A the form of Certificate of Designation of Series A Junior Participating Preferred Stock (Form 8-A, File No. 1-10477). (a) Amendment No. 1 to the Rights Agreement dated February 24, 1994 (Form 10-K for 1994). (b) Amendment No. 2 to the Rights Agreement dated December 8, 2000 (Form 8-K for December 21, 2000).
4.4	Certificate of Designation for 6% Convertible Redeemable Preferred Stock (Form 10-K for 1994).
4.5	Amended and Restated Credit Agreement dated as of May 30, 1995, among the Company, Morgan Guaranty Trust Company, as agent and the banks named therein. (a) Amendment No. 1 to Credit Agreement dated September 15, 1995 (Form 10-K for 1995). (b) Amendment No. 2 to Credit Agreement dated December 24, 1996 (Form 10-K for 1996).
4.7	Note Purchase Agreement dated November 14, 1997, among the Company and the purchasers named therein (Form 10-K for 1997).
4.8	Note Purchase Agreement dated as of July 26, 2001 among Cabot Oil & Gas Corporation and the Purchasers listed therein (Form 8-K for August 30, 2001).
4.9	Credit Agreement dated as of October 28, 2002 among the Company, the Banks Parties Hereto and Fleet National Bank, as administrative agent (Form 10-Q for the quarter ended September 30, 2002). (a) Amendment No. 1 to Credit Agreement dated December 10, 2004.
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).

Exhibit Number	Description
10.9	Amendment Agreement (amending the Transaction Agreement and the Tax Sharing Agreement) dated March 25, 1991 (incorporated by reference from Cabot Corporation's Schedule 13E-4, Am. No. 6, File No. 5-30636).
10.10	Savings Investment Plan & Trust Agreement of the Company (Form 10-K for 1991). (a) First Amendment to the Savings Investment Plan dated May 21, 1993 (Form S-8 dated November 1, 1993). (b) Second Amendment to the Savings Investment Plan dated May 21, 1993 (Form S-8 dated November 1, 1993). (c) First through Fifth Amendments to the Trust Agreement (Form 10-K for 1995). (d) Third through Fifth Amendments to the Savings Investment Plan (Form 10-K for 1996).
10.11	Supplemental Executive Retirement Agreements of the Company (Form 10-K for 1991).
10.12	Settlement Agreement and Mutual Release (Tax Issues) between Cabot Corporation and the Company dated July 7, 1992 (Form 10-Q for the quarter ended June 30, 1992).
10.13	Agreement of Merger dated February 25, 1994, among Washington Energy Company, Washington Energy Resources Company, the Company and COG Acquisition Company (Form 10-K for 1993).
10.14	1990 Non-employee Director Stock Option Plan of the Company (Form S-8 dated June 23, 1990). (a) First Amendment to 1990 Non-employee Director Stock Option Plan (Post-Effective Amendment No. 2 to Form S-8 dated March 7, 1994). (b) Second Amendment to 1990 Non-employee Director Stock Option Plan (Form 10-K for 1995).
10.15	Second Amended and Restated 1994 Long-Term Incentive Plan of the Company (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).
10.26	2004 Incentive Plan (Form 10-Q for the quarter ended June 30, 2004).
10.27	2004 Performance Award Agreement (Form 10-Q for the quarter ended June 30, 2004).
10.28	2004 Annual Target Cash Incentive Plan Measurement Criteria for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
10.29	Form of Restricted Stock Awards Terms and Conditions for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).

Exhibit Number	Description
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.
31.1	302 Certification – Chairman, President and Chief Executive Officer.
31.2	302 Certification – Vice President and Chief Financial Officer.
32.1	906 Certification.
99.1	Miller and Lents, Ltd. Review Letter.

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 2nd of March 2005.

CABOT OIL & GAS CORPORATION

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

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

Signature	Title	Date
/s/ Dan O. Dinges Dan O. Dinges	Chairman, President and Chief Executive Officer (Principal Executive Officer)	March 2, 2005
/s/ Scott C. Schroeder Scott C. Schroeder	Vice President and Chief Financial Officer (Principal Financial Officer)	March 2, 2005
/s/ Henry C. Smyth Henry C. Smyth	Vice President, Controller and Treasurer (Principal Accounting Officer)	March 2, 2005
/s/ Robert F. Bailey Robert F. Bailey	Director	March 2, 2005
/s/ John G. L. Cabot John G. L. Cabot	Director	March 2, 2005
/s/ James G. Floyd James G. Floyd	Director	March 2, 2005
/s/ Robert Kelley Robert Kelley	Director	March 2, 2005
/s/ C. Wayne Nance C. Wayne Nance	Director	March 2, 2005
/s/ P. Dexter Peacock P. Dexter Peacock	Director	March 2, 2005
/s/ William P. Vititoe William P. Vititoe	Director	March 2, 2005

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Corporate Information

Officers

Dan O. Dinges
Chairman, President and
Chief Executive Officer

Michael B. Walen
Senior Vice President,
Exploration and Production

Scott C. Schroeder
Vice President and
Chief Financial Officer

J. Scott Arnold
Vice President, Land and
Associate General Counsel

R. Scott Butler
Vice President, Regional Manager,
Western Region

Robert G. Drake
Vice President, Information
Services and Operational
Accounting

Abraham D. Garza
Vice President, Human Resources

Jeffrey W. Hutton
Vice President, Marketing

Thomas S. Liberatore
Vice President, Regional Manager,
Eastern Region

Lisa A. Machesney
Vice President, Managing Counsel
and Corporate Secretary

Henry C. Smyth
Vice President, Controller
and Treasurer

Annual Meeting

The annual meeting of the shareholders will be held Thursday, April 28, 2005, at 8:30 a.m. (CDT) at the corporate office in Houston, Texas.

Corporate Office

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1200 Enclave Parkway
Houston, Texas 77077
P. O. Box 4544
Houston, Texas 77210-4544
(281) 589-4600
www.cabotog.com

Independent Registered Public Accounting Firm

PricewaterhouseCoopers LLP
1201 Louisiana, Suite 2900
Houston, Texas 77002

Reserve Engineers

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

Investor Relations

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

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

Transfer Agent/Registrar

The Bank of New York
Shareholder Relations Department
P. O. Box 11258
Church Street Station
New York, New York 10286
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(888) 269-5221 (Hearing Impaired - TDD Phone)
shareowner@bankofny.com
www.stockbny.com

Send Certificates for Transfer
and Address Changes to:

Receive and Deliver Department
P. O. Box 11002
Church Street Station
New York, New York 10286

Corporate Governance Matters

On May 21, 2004, the Company's CEO, Dan O. Dinges, certified to the NYSE that he was not aware of any violation by the Company of NYSE corporate governance listing standards. Further, Mr. Dinges and the CFO, Scott C. Schroeder, made the requisite Section 302 certifications in the 2004 quarterly reports on Form 10-Q and the 2004 annual report on Form 10-K as mandated by the Sarbanes-Oxley Act of 2002.

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Cabot Oil & Gas Corporation