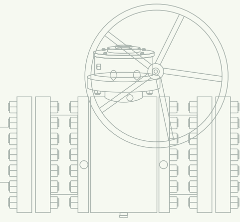
CABOT WORKS

CABOT OIL & GAS CORPORATION

— 2008 ANNUAL REPORT —

Cabot Oil & Gas Corporation, headquartered in Houston, Texas is a leading North American exploration and production independent. The Company's reserves are focused in both conventional and unconventional basins including the East, the West (Rocky Mountain and Mid-Continent), the Gulf Coast (South and East Texas to North Louisiana) and in Canada.



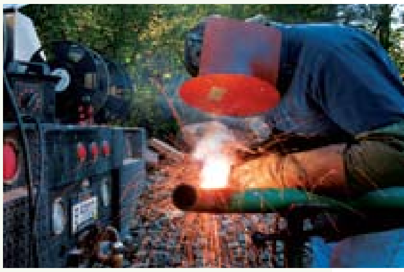
— TO OUR SHAREHOLDERS —

A year of extremes — that is the best characterization I can think of for 2008. The year began with promise and excitement; it peaked in July with historic natural gas commodity prices, but closed with a great deal of uncertainty as the world's credit markets and economies came to a grinding halt.

For 2008, Cabot focused its investment efforts on our East Texas assets and the East region. With the strength of our underlevered capital structure and a strong hedge position, we were able to aggressively exploit these areas, adding significant acreage positions and reserves in the process. This successful execution resulted in several achievements including:

- Adding 292,381 net acres to our leasehold position in both of the targeted regions, and our West region.
- Closing our first producing property acquisition in seven years focused in East Texas.
- Funding these acquisitions with external financing of new debt and new common equity (which was timed to coincide with the S&P 500 index inclusion), that marked the first time since 2001 for adding new external capital to the business.

Couple these activities with our largest drilling program and Cabot had the ingredients for a strong year.



Cabot Oil & Gas Corporation

In the last few months of the year, the landscape changed significantly…

- A credit crisis occurred that effectively shut down the capital markets.
- Several traditionally solid, household name companies were facing bankruptcy.
- A rush by investors to cash as panic became the daily mantra in the markets.
- In the energy sector:
  - crude oil prices dropped more than $100 per barrel
  - natural gas prices declined more than $7 per Mcf.

In spite of the tumultuous year, in 2008, Cabot Oil & Gas experienced the best year in its history – establishing several new benchmarks for excellence along the way. These achievements spanned both the financial, and the operational spectrum with new highs for:

- **Net income of $211.3 million and $2.10 per share**
- **Discretionary cash flow of $608.7 million**
- **Investment program of $1.5 billion**
- **Reserves adds of 303.9 Bcfe (Drilling) or 421.5 Bcfe (Drilling, Revisions, Purchases)**
- **Total proved reserves of 1,942.0 Bcfe**
- **Full year production of 95.2 Bcfe**

Bottom line, Cabot works! As evidenced by these statistics, along with our financial strength, Cabot is positioned to weather the uncertainty of the future. Our conservative operating strategy, together with our philosophy to operate within our means, has served the Company and its shareholders well in the past and will continue to do so in the future. The above statistics individually give us optimism about the potential that lies ahead for our Company as the industry works through this cycle.

LOOKING FORWARD

As we plan and implement our 2009 program, shareholders should take comfort that Cabot's prudent management style will not only continue to protect its balance sheet, but also continue to add revenue producing assets to our Company at economic levels. Again, as we move forward, we continue to add value. A measure that Cabot's model works!

We will continue to adapt our plan of capital allocation in order to invest at levels that fall within the anticipated cash flow for the year. This plan is almost entirely directed towards our two main areas of focus from 2008 – the Marcellus Shale of Pennsylvania (further detailed on page 16) and the Bossier/Haynesville Shale, along with various limestone formations, of East Texas (discussed in detail on page 8). These two areas remain the most exciting plays for our industry.

PIPELINE ACTIVITY IN
NORTHEAST PENNSYLVANIA

WE HAVE A SOLID PRODUCTION BASE (10-15% ANNUAL DECLINE), SOLID BALANCE SHEET AND A CONSERVATIVE BENT THAT HAS POSITIONED US TO PROSPER IN THIS ENVIRONMENT.

Execution of our 2009 program is supported by a strong balance sheet and underpinned with a hedge position that covers over 50 percent of anticipated 2009 equivalent production. The minimum weighted average natural gas price for these hedges is $10.11 per Mcf, while the average hedge for oil is $125.25 per barrel. The net positive from this hedge position to our cash flow affords us the ability to have a larger investment program for 2009, and still maintain our spending discipline.

It is widely anticipated that the cost of goods and services will mimic the dramatic declines we have realized in commodity prices. Assuming moderate commodity prices, our margin per dollar invested will increase, along with the efficiencies in our operations that are employed by our talented workforce, both maximizing our 2009 investment dollars.

Our industry has achieved the ability to identify and produce an abundant resource of natural gas, a cleaner resource capable of meeting our country's energy needs of the future. The enhanced development of natural gas (Cabot is 97% natural gas) was driven by a thriving economy, new technologies, and easy access to capital. With employment of new technologies and exploitation of shales, our industry can provide the nation with an adequate supply of natural gas, one of the most cost effective and cleanest alternative energy sources available for the foreseeable future.

As we enter 2009, we continue to see an increase in supply because of 2008 record levels of drilling activity. Demand has fallen as a result of the weak economy – even with the coldest broadly based winter in more than two decades. To this end, we (as an industry) have seen a dramatic slowdown in drilling activity. This slowdown will help to stabilize the supply/demand dynamics.

1 DAN O. DINGES, CHAIRMAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER

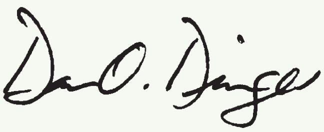
2 CABOT'S SENIOR EXECUTIVE MANAGEMENT TEAM, LEFT TO RIGHT:
MICHAEL B. WALEN, SENIOR VICE PRESIDENT AND CHIEF OPERATING OFFICER; DAN O. DINGES;
SCOTT C. SCHROEDER, VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

We have a solid production base (10-15% annual base decline), solid balance sheet and a conservative bent that has positioned us to prosper in this environment. I cannot say how long this economic downturn will last, however we are well equipped to manage and enhance shareholder value in these times. I continue to look forward to the challenging, but rewarding environment we face in 2009.

I would like to take this opportunity to thank John Cabot for his years of service as a member of our Board. John retired from the Board after serving as a director since Cabot's inception in 1990. John's insights about the business from his long association with our industry were always a valued and welcome addition to the strategic decisions we made. We thank John for this commitment to Cabot Oil & Gas Corporation.

Additionally, I would like to thank our Board of Directors and our employees for their support of Cabot and for their commitment to make Cabot stand out in these times. I remain excited about our future and look forward to delivering value accretion in a very challenging, but opportunistic time.

Sincerely,



Dan O. Dinges
Chairman, President and Chief Executive Officer

TOMMY MOORE, PRODUCTION SUPERINTENDENT - EAST TEXAS

EAST TEXAS

accelerating

WITH EXTENSIVE ACQUISITION EFFORTS

Cabot's efforts to establish a presence in East Texas accelerated during 2005. This exploration effort was established to identify areas where the Company could acquire large acreage positions in multiple plays. At the time of this initial interest, Cabot had no significant leasehold position and no production in East Texas.

Fast forward to 2008 and with an extensive acquisition effort – both for leasehold and producing property – the acreage position has grown from zero to over 130,000 gross acres in East Texas. Also in 2008, Cabot's efforts centered around testing various prospective shale horizons throughout the East Texas acreage position. Specifically targeted zones for new initiatives were the Bossier Shale, Haynesville Shale and Haynesville Limestone. This effort was done both vertically and horizontally. Figure #1 visually highlights the stratigraphic column in East Texas.

The two main areas of shale exploitation are Minden and the greater County Line area.

The Company made its largest acquisition in its history, the first major one in seven years, when it added to its Minden Field in August (effectively tripling the footprint).

130,000

GROSS ACRES IN EAST TEXAS

FRACTURE STIMULATION IN EAST TEXAS

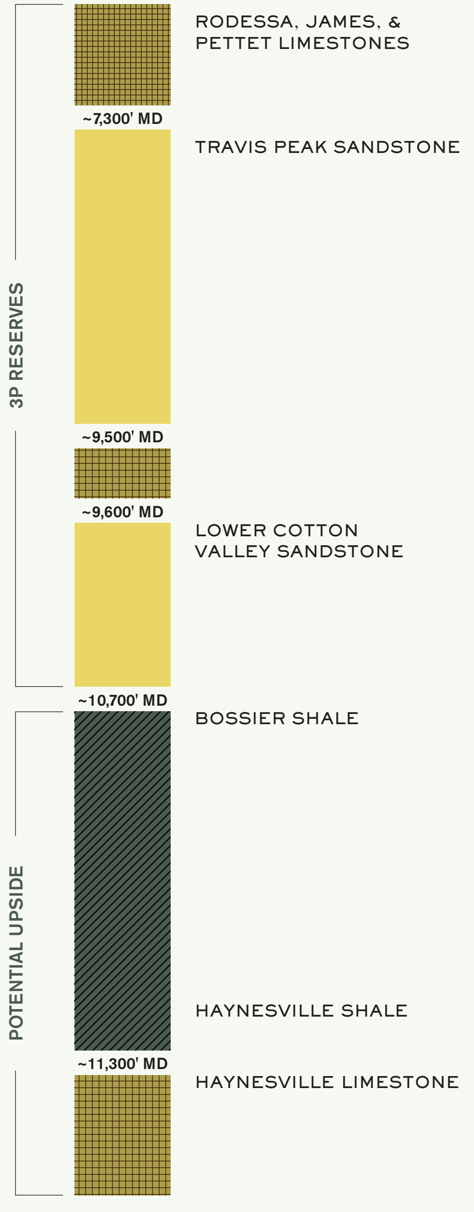
MINDEN

At Minden, the Company now has drilled 106 wells, producing from multiple Lower Cotton Valley zones with some minor Upper Travis Peak production. In addition, Cabot has established production from the deeper Haynesville Shale (Bossier) and Haynesville Limestone within the acreage position. Cabot continues to evaluate well spacing and completion techniques for those intervals. The Company has added an extensive infrastructure and gathering system consisting of 73 miles of pipe, 22 satellite tank batteries and two central production facilities. This integrated effort, together with the large acreage footprint, affords Cabot many years of drilling inventory at Minden for Lower Cotton Valley, Bossier and Haynesville potential.

COUNTY LINE

Cabot has now drilled or participated in 46 horizontal James Limestone wells with current gross production at County Line of approximately 75 Mmcf per day. The Company has expanded its acreage play to the north through trades with a major oil company. In addition, Cabot is currently evaluating potential in the Bossier and Haynesville sections in the southern portion of the County Line acreage. Cabot has now expanded the acreage position to over 60,000 gross acres in the greater County Line area and will continue to evaluate and exploit the deep potential. The expected outcome from these efforts are multi-year drilling programs in the James Limestone, Bossier and Haynesville Shales, along with the Haynesville Limestone.

FIGURE 1
EAST TEXAS STRATIGRAPHIC SECTION
MINDEN AREA



MINDEN EXPANSION

In early 2008, Cabot was contacted about a potential acreage/production acquisition adjacent to the Company's core Minden Field in Rusk County. Based on the experience gained at Minden over the last several years, this opportunity provides Cabot additional reserve and production growth in the lower Cotton Valley section. Production history at Minden indicated significant lower Cotton Valley down spacing potential. In addition, through selective testing and deepening, Cabot identified a Bossier and Haynesville Shale and Limestone section that would provide significant upside. Cabot closed on this acquisition in August, 2008 with an effective date of May 1, 2008. In this deal, the Company added 25,000 gross acres, 32 Mmcfe per day of gross production, 172 Bcfe of proved reserves, 778 Bcfe of 2P and 3P reserves and 64 producing wells. Cabot will continue to develop this field through commingled completions and horizontal drilling opportunities.

FRAC JOB IN PENNSYLVANIA

EAST REGION

delivering

SIGNIFICANT PROGRESS IN SHALE ACTIVITY

MARCELLUS

In a company's life, there are times when an idea creates an opportunity that can positively change its future. The Marcellus Shale for Cabot is just such a game-changing event.

Last year at this time Cabot's effort was in the very early stages of exploitation with plans to drill 20 wells in Pennsylvania and 68 wells in West Virginia. The West Virginia results, although economic, did not compare to the robust performance of the 20 wells in Pennsylvania. Of these 20 wells, five were horizontals and 15 were verticals. First production occurred in July and at year-end 15 wells were producing, although only one horizontal. The exit rate of production from these wells at year-end was approaching 20 Mmcf per day.

The Marcellus acreage in Pennsylvania, which now totals over 160,000 gross acres, is focused over what is believed to be a sweet spot in the play. To effectively exploit this position, the Company will begin a two-phased approach to future drilling. The first phase, labeled core area development drilling, is already under way. To further the success, in 2009 Cabot plans to drill 60 wells in Susquehanna County, and at this time the effort is split equally at 30 verticals and 30 horizontals. While the Company has had early success, this is still very much a work in progress as Cabot continues to use different technologies to achieve the best results. Larger casing, more and longer horizontals, and micro seismic application to evaluate fracturing technologies are just a few of the areas being evaluated to determine the most effective development course of action.

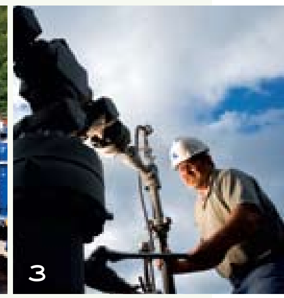
DANNY WINFREE, PIPELINE SPECIALIST AND
RAY MORGAN, LEAD FIELD OPERATOR - SISSONVILLE

The Marcellus initiative in northeastern Pennsylvania is gaining momentum and starts 2009 producing nearly 20 Mmcf per day. This production is from 14 vertical wells and one horizontal well. Most recently, Cabot completed its first Marcellus horizontal well with a measured depth of 8,925' and a horizontal leg at 2,000' using a six-stage frac. The result was a 24-hour average initial production rate of 6.4 Mmcf per day.

15 WELLS

PRODUCING NEARLY
20 MMCF PER DAY
AT YEAR-END.

CHRIS LOWMAN, DRILLING ENGINEER - SUSQUEHANNA



1 JOHN PAPSO, MANAGER, ENGINEERING AND DOUG GOSNELL, RESERVOIR ENGINEERING - CHARLESTON

2 FROM LEFT TO RIGHT: STEVE PARILAC, GENERAL FOREMAN; JEFF MINOTTI, GENERAL FOREMAN; WHITNEY JOHNSON, DISTRICT SUPERINTENDENT - SISSONVILLE

3 TIM LEWIS, FIELD OPERATOR - GRANTSVILLE

The second phase, labeled extension drilling, should begin in 2010. The goal of this effort will be to expand the pipeline infrastructure and drill primary term leases. Cabot's focus will be to extend the Company's infrastructure, allowing Cabot to drill and prove up all of the Company's existing leases. Total number of wells will be dependant on the mix between vertical and horizontal wells. Subsequent to this effort Cabot will initiate a back-fill drilling program along the Company's existing pipeline route.

The overall effort will achieve the most efficient, economic operations, where Cabot will maximize production growth and lease retention, all within the capital constraints of the environment.

What affords Cabot such optimism is not only the early success, but the Company's extensive knowledge of the basin including the importance of infrastructure. This play was designed around the location of the thickest, richest Marcellus Shale and equally as important, access to an interstate pipeline.

Cabot has successfully negotiated an exit for its gas to various markets, which ramps up to 90 Mmcf per day by August 2010. Additionally, with the pipeline operating knowledge within the organization drawing on over 100 years of designing and building infrastructure in Appalachia, the team has planned an aggressive program of pipeline expansion in Pennsylvania for 2009 with existing and additional interstate pipeline connections, compression, and 25 miles of new gathering pipelines tied to a 60 well program, which is projected to increase production by multiples over the Company's 2008 exit rate.

Bottom line, Cabot has years of opportunity and inventory here as the Company continues to expand its program.

MINDEN FIELD, RUSK COUNTY

FINANCIAL HIGHLIGHTS

INCOME STATEMENT	2006	2007	2008
Operating Revenue	$ 762.0	$ 732.2	**$ 945.8**
Operating Expenses	465.1	470.9	**626.8**
Operating Income	528.9	274.7	**372.0**
Net Income	321.2	167.4	**211.3**
Per Share [1]	3.32	1.73	**2.10**
Common Dividend Per Share	$ 0.08	$ 0.11	**$ 0.12**
Average Common Shares Outstanding *(In thousands)* [1]	96,803	96,978	**100,737**

NET INCOME

2006 $321.2
2007 $167.4
2008 $211.3

CASH FLOW	2006	2007	2008
Discretionary Cash Flow [2]	$ 355.8	$ 472.7	**$ 608.7**
Per Share [1]	3.68	4.87	**6.04**
Cash From Operations	357.1	462.1	**634.4**
Cash From Investing	(187.4)	(589.9)	**(1,452.3)**
Cash From Financing	(138.5)	104.4	**827.4**
Net Cash	$ 31.2	$ (23.4)	**$ 9.6**

DISCRETIONARY CASH FLOW

2006 $355.8
2007 $472.7
2008 $608.7

[1] Prior years have been adjusted to reflect a 2-for-1 stock split in 2007.
[2] Net income plus non-cash items from operations and exploration expenses.

* In millions, except share amounts

DEBT MATURITY SCHEDULE

2009 $36
2010 $169[3]
2011 $75
2013 $75
2016 $20
2018 $312
2020 $100
2023 $80

BALANCE SHEET	2006	2007	2008
Current Assets	$ 315.7	$ 217.5	**$ 460.6**
Current Liabilities	251.0	248.3	**378.9**
Short-Term Debt	20.0	20.0	**35.9**
Long-Term Debt	220.0	330.0	**831.1**
Stockholders' Equity *(Successful Efforts Method)*	$ 945.2	$ 1,070.3	**$ 1,790.6**

CURRENT ASSETS

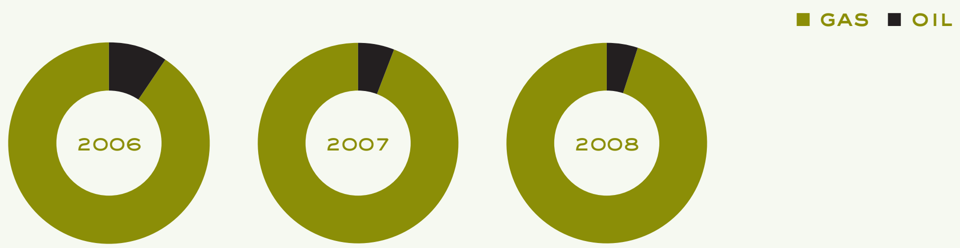
2006 $315.7
2007 $217.5
2008 $460.6

[3] Includes the final maturity for debt associated with the Revolving Credit Facility, which is planned for renegotiation in early 2009.

OPERATIONAL HIGHLIGHTS

PRODUCTION	2006	2007	2008
Gas *(Bcf)*	79.7	80.5	**90.4**
Oil *(MBbl)*	1,415	830	**794**
Total *(Bcfe)*	88.2	85.5	**95.2**
Mmcfe/day	241.7	234.1	**260.1**

PRODUCTION GAS/OIL MIX



WELLS DRILLED	2006	2007	2008
Total Gross	387	461	**432**
Total Net	307	391	**355**
Gross Success Rate %	96%	96%	**97%**

PROVED RESERVES [1]	2006	2007	2008
Natural Gas *(Bcf)*	1,368.3	1,560.0	**1,886.0**
Oil, Condensate and Natural Gas Liquids *(Mmbbl)*	8.0	9.3	**9.3**
Total Proved *(Bcfe)*	1,416.1	1,615.9	**1,942.0**
Total Developed *(Bcfe)*	1,032.2	1,176.1	**1,348.5**
% Gas	97%	97%	**97%**
% Developed	73%	73%	**69%**

TOTAL PROVED RESERVES

2006 1,416.1

2007 1,615.9

2008 1,942.0

RESERVE ADDITIONS	2006	2007	2008
Drilling Additions, Revisions and Purchases *(Bcfe)*	241.1	285.2	**421.5**
Reserve Replacement %	273%	334%	**443%**

RESERVE REPLACEMENT %

2006 273%

2007 334%

2008 443%

FINDING & DEVELOPMENT COSTS	2006	2007	2008
Additions *($/Mcfe)*	$ 1.97	$ 2.14	**$ 2.25**
Additions, Revisions *($/Mcfe)*	$ 2.09	$ 2.09	**$ 2.77**
Additions, Revisions, and Purchases *($/Mcfe)*	$ 2.10	$ 2.07	**$ 3.06**

ADDITIONS

2006 $1.97

2007 $2.14

2008 $2.25

[1] Changes in reserves from year to year reflect drilling additions and revisions as well as reserves purchased and sold.

BOARD OF DIRECTORS

DIRECTORS

Dan O. Dinges
Chairman, President and Chief Executive Officer

Rhys J. Best
Former Chairman of the Board and Chief Executive Officer, Lone Star Technologies, Inc.

David M. Carmichael
Former Vice Chairman and Chairman of the Management Committee, KN Energy, Inc.

Robert L. Keiser
Former Chairman of the Board, Oryx Energy Company

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

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

COMMITTEES

AUDIT COMMITTEE
Robert Kelley – *Chairman*
Rhys J. Best
Robert L. Keiser

COMPENSATION COMMITTEE
William P. Vititoe – *Chairman*
David M. Carmichael
P. Dexter Peacock

EXECUTIVE COMMITTEE
P. Dexter Peacock – *Chairman*
Dan O. Dinges
David M. Carmichael

CORPORATE GOVERNANCE AND NOMINATIONS COMMITTEE
David M. Carmichael – *Chairman*
P. Dexter Peacock
William P. Vititoe

SAFETY AND ENVIRONMENTAL AFFAIRS COMMITTEE
Robert L. Keiser – *Chairman*
Rhys J. Best
Robert Kelley

CORPORATE INFORMATION

OFFICERS

Dan O. Dinges
Chairman, President and Chief Executive Officer

Michael B. Walen
Senior Vice President, Chief Operating Officer

Scott C. Schroeder
Vice President and Chief Financial Officer

J. Scott Arnold
Vice President, Land and General Counsel

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, East 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 Tuesday, April 28, 2009, at 8:00 a.m. (Central) at the corporate office in Houston, Texas.

CORPORATE OFFICE

Cabot Oil & Gas Corporation
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

CORPORATE INFORMATION

RESERVE ENGINEERS
Miller & Lents, Ltd
Oil & Gas Consultants
909 Fannin, Suite 1300
Houston, Texas 77010

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
BNY Mellon Shareowner Services
P.O. Box 358015
Pittsburgh, Pennsylvania 15252-8015
or
480 Washington Boulevard
Jersey City, New Jersey 07310-1900

Telephone:	866-201-5655
TDD for Hearing Impaired:	800-231-5469
Foreign Shareowners:	201-680-6578
TDD Foreign Shareowners:	201-680-6610

Web Site address:
www.bnymellon.com/shareowner/isd

Send Certificates for Transfer and Address Changes as follows:

Via the U.S. Postal Service:
BNY Mellon Shareowner Services
ATTN: Stock Transfer Dept.
P.O. Box 358010
Pittsburgh, Pennsylvania 15252-8010

Via overnight or express mail services:
BNY Mellon Shareowner Services
ATTN: Stock Transfer Dept. – 6th Floor
500 Ross St.
Pittsburgh, Pennsylvania 15262

CORPORATE
GOVERNANCE MATTERS
On May 25, 2008, 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 2008 quarterly reports on Form 10-Q and the 2008 annual report on Form 10-K as mandated by the Sarbanes-Oxley Act of 2002.

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

FORM 10-K

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

For the fiscal year ended December 31, 2008

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, including area code)

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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 ☒ 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 a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of Common Stock, par value $.10 per share ("Common Stock"), held by non-affiliates as of the last business day of registrant's most recently completed second fiscal quarter (based upon the closing sales price on the New York Stock Exchange on June 30, 2008) was approximately $7.0 billion.

As of February 19, 2009, there were 103,447,221 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, 2009 are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

The statements regarding future financial and operating performance and results, strategic pursuits and goals, 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. See “Risk Factors” in Item 1A for additional information about these risks and uncertainties. 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. See “Forward-Looking Information” for further details.

CERTAIN DEFINITIONS

The following is a list of commonly used terms and their definitions included within this Annual Report on Form 10-K:

Abbreviated Term	**Definition**
Mcf	Thousand cubic feet
Mmcf	Million cubic feet
Bcf	Billion cubic feet
Bbl	Barrel
Mbbls	Thousand barrels
Mcfe	Thousand cubic feet of natural gas equivalents
Mmcfe	Million cubic feet of natural gas equivalents
Bcfe	Billion cubic feet of natural gas equivalents
Mmbtu	Million British thermal units
NGL	Natural gas liquids

PART I

ITEM 1. BUSINESS

OVERVIEW

Cabot Oil & Gas Corporation is an independent oil and gas company engaged in the development, exploitation and exploration of oil and gas properties located in North America. Our four principal areas of operation are the Appalachian Basin, onshore Gulf Coast, including south and east Texas and north Louisiana, the Rocky Mountains and the Anadarko Basin. We also operate in the deep gas basin of Western Canada. Operationally, we have four regional offices located in Houston, Texas; Charleston, West Virginia; Denver, Colorado; and Calgary, Alberta.

In 2008, energy commodity prices increased to all-time high levels for the first half of the year and then quickly declined to 2007 levels during the second half of 2008. Our 2008 average realized natural gas price was $8.39 per Mcf, 16% higher than the 2007 average realized price of $7.23 per Mcf. Our 2008 average realized crude oil price was $89.11 per Bbl, 33% higher than the 2007 average realized price of $67.16 per Bbl. These realized prices include realized gains and losses resulting from commodity derivatives (zero-cost collars or swaps). For information about the impact of these derivatives on realized prices, refer to the "Results of Operations" section in Item 7 of this Annual Report on Form 10-K.

In 2008, we pursued and completed the largest investment program in our history, totaling $1,481.0 million. This included our largest producing property acquisition ($625.0 million), lease acquisition ($152.7 million) and drilling and facilities ($624.3 million) programs. The producing property and lease acquisition activity were funded by issuances of new long-term debt and common stock during the year. The capital spending (excluding the acquisition activity) was funded largely through cash flow from operations and, to a lesser extent, borrowings on our revolving credit facility.

We intend to manage our balance sheet in an effort to ensure that we have sufficient liquidity, and we intend to maintain spending discipline. We believe these strategies continue to be appropriate for our portfolio of projects and the current industry environment, and we believe our balance sheet and availability under our credit facility provide sufficient liquidity to pursue our 2009 program.

In August 2008, we completed the acquisition of producing properties, leasehold acreage and a natural gas gathering infrastructure in east Texas (the "east Texas acquisition"). We paid total net cash consideration of approximately $604.0 million (see Note 2 of the Notes to the Consolidated Financial Statements for further details). In order to finance the east Texas acquisition, we completed a public offering of 5,002,500 shares of our common stock in June 2008, receiving net proceeds of $313.5 million (see Note 9 of the Notes to the Consolidated Financial Statements for further details), and we closed a private placement in July 2008 of $425 million principal amount of senior unsecured fixed rate notes (see Note 4 of the Notes to the Consolidated Financial Statements for further details).

On an equivalent basis, our production level in 2008 increased by 11% from 2007. We produced 95.2 Bcfe, or 260.1 Mmcfe per day, in 2008, as compared to 85.5 Bcfe, or 234.1 Mmcfe per day, in 2007. Natural gas production increased to 90.4 Bcf in 2008 from 80.5 Bcf in 2007 primarily due to *(1)* increased natural gas production in the Gulf Coast region due to increased production in the Minden field, largely due to the properties we acquired in the east Texas acquisition in August 2008, and increased drilling in the County Line field, *(2)* increased production in the West region associated with an increase in the drilling program, *(3)* increased production in the East region due to increased drilling activity in West Virginia and northeastern Pennsylvania and *(4)* increased production in Canada due to increased drilling activity in the Hinton field. Oil production decreased by 41 Mbbls from 823 Mbbls in 2007 to 782 Mbbls in 2008 due primarily to natural declines in the Gulf Coast and West regions.

For the year ended December 31, 2008, we drilled 432 gross wells (355 net) with a success rate of 97% compared to 461 gross wells (391 net) with a success rate of 96% for the prior year. In 2009, we plan to drill approximately 148 gross wells (122.3 net). The number of wells we plan to drill in 2009 is down from 2008 primarily due to lower commodity prices resulting from the global decline in economic activity as well as our ongoing strategy of managing our capital investment program within anticipated cash flow. We plan to concentrate our capital program for 2009 in east Texas and northeast Pennsylvania where opportunities for growth are currently concentrated.

Our 2008 capital and exploration spending was $1.5 billion compared to $636.2 million of total capital and exploration spending in 2007. In both 2008 and 2007, we allocated our planned program for capital and exploration expenditures among our various operating regions based on return expectations, availability of services and human resources. We plan to continue such method of allocation in 2009. Funding of the program is expected to be provided by operating cash flow, existing cash and increased borrowings under our credit facility, if required. We may also reduce our budgeted capital and exploration spending to maintain sufficient liquidity. We remain focused on our strategies of pursuing lower risk drilling opportunities that provide more predictable results on our accumulated acreage position. For 2009, the Gulf Coast and East regions are expected to receive approximately 90% of the anticipated capital program, with the majority of the remainder dedicated to the West region. We believe these strategies are appropriate in the current industry environment and will continue to add shareholder value over the long-term. In 2009, we plan to spend approximately $475 million on capital and exploration activities.

Our proved reserves totaled approximately 1,942 Bcfe at December 31, 2008, of which 97% were natural gas. This reserve level was up by 20% from 1,616 Bcfe at December 31, 2007 on the strength of results from our drilling program, the increase in our capital spending and the east Texas acquisition.

The following table presents certain reserve, production and well information as of December 31, 2008.

			West				
	East	**Gulf Coast**	**Rocky Mountains**	**Mid-Continent**	**Total**	**Canada**	**Total**
Proved Reserves at Year End *(Bcfe)*							
Developed	613.4	317.3	201.9	178.4	380.3	37.5	**1,348.5**
Undeveloped	258.4	237.3	69.5	25.5	95.0	2.8	**593.5**
Total	871.8	554.6	271.4	203.9	475.3	40.3	**1,942.0**
Average Daily Production *(Mmcfe per day)*	69.1	104.1	41.3	33.9	75.2	11.7	**260.1**
Reserve Life Index *(In years)*[1]	34.4	14.6	18.0	16.4	17.3	9.5	**20.4**
Gross Wells	3,382	844	716	844	1,560	43	**5,829**
Net Wells[2]	3,162.6	592.2	329.4	594.5	923.9	16.2	**4,694.9**
Percent Wells Operated *(Gross)*	96.6%	75.0%	52.0%	78.1%	66.1%	58.1%	**85.0%**

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

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

Our interest in both developed and undeveloped properties is primarily in the form of leasehold interests held under customary mineral leases. These leases provide us the right, in general, to develop oil and/or natural gas on the properties. Their primary terms range in length from approximately three to ten years. These properties are held for longer periods if production is established. We own leasehold rights on approximately 3.0 million gross acres. In addition, we own fee interest in approximately 0.2 million gross acres, primarily in West Virginia. Our ten largest fields, which are fields with 2.5% or greater of total company proved reserves, make up approximately 53% of total company proved reserves.

The following table presents certain information with respect to our principal properties as of and for the year ended December 31, 2008.

	Production Volumes						
	Natural Gas (Mcf/ Day)	Oil and NGLs (Bbls/ Day)	Total (Mcfe/Day)	Proved Reserves at Year-End (Mmcfe)	Gross Producing Wells	Gross Wells Drilled	Nature of Interest (Working/Royalty)
West Virginia							
Sissonville.	9,263	4	9,285	138,484	445	61	W/R
Pineville	11,456	—	11,456	105,466	299	11	W/R
Logan-Holden-Dingess	7,359	—	7,359	84,507	217	17	W
Big Creek	4,587	—	4,587	70,956	210	16	W
Hernshaw-Bull Creek	3,977	—	3,977	54,624	261	14	W/R
Huff Creek	3,639	—	3,639	51,810	124	25	W
Pensylvania							
Dimock (Susquehanna area)	1,653	—	1,653	66,734	22	20	W
Oklahoma							
Mocane-Laverne	9,989	—	9,991	64,535	242	2	W/R
East Texas							
Brachfield Southeast (Minden area)	23,905	412	26,373	323,886	179	29	W
Angie (County Line area)	27,900	40	28,138	65,213	48	36	W

EAST REGION

Our East region activities are concentrated primarily in West Virginia and Pennsylvania. This region is managed from our office in Charleston, West Virginia. In this region, our assets include a large acreage position, a high concentration of wells, natural gas gathering and pipeline systems, and storage capacity.

Capital and exploration expenditures for 2008 were $369.6 million, or 24% of our total 2008 capital and exploration expenditures, compared to $178.6 million for 2007, or 28% of our total 2007 capital and exploration expenditures. This increase was substantially driven by a $103.1 million increase in lease acquisition costs year-over-year. For 2009, we have budgeted approximately $200 million for capital and exploration expenditures in the region.

At December 31, 2008, we had 3,382 wells (3,162.6 net), of which 3,268 wells are operated by us. There are multiple producing intervals that include the Big Lime, Weir, Berea and Devonian (including Marcellus) Shale formations at depths primarily ranging from 1,100 to 9,500 feet, with an average depth of approximately 4,100 feet. Average net daily production in 2008 was 69.1 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2008 was 25.2 Bcf and 23 Mbbls, respectively.

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 region reserves is relatively long. At December 31, 2008, we had 871.8 Bcfe of proved reserves (substantially all natural gas) in the East region, constituting 45% of our total proved reserves. Developed and undeveloped reserves made up 613.4 Bcfe and 258.4 Bcfe of the total proved reserves for the East region, respectively. While no properties are individually significant to our company as a whole, the Sissonville, Pineville, Logan-Holden-Dingess, Big Creek, Hernshaw-Bullcreek, and Huff Creek fields in West Virginia and the Dimock field in the Susquehanna area of Pennsylvania are included in our ten largest fields and together contain approximately 30% of our total company proved equivalent reserves.

In 2008, we drilled 212 wells (205.4 net) in the East region, of which 208 wells (201.4 net) were development and extension wells. In 2009, we plan to drill approximately 63 wells (62.8 net), primarily in the Dimock field.

In 2008, we produced and marketed approximately 62 barrels of crude oil/condensate/NGL per day in the East region at market responsive prices.

Ancillary to our exploration, development and production operations, we operated a number of gas gathering and transmission pipeline systems, made up of approximately 3,200 miles of pipeline with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2008. The majority of our pipeline infrastructure in West Virginia is regulated by the Federal Energy Regulatory Commission (FERC) for interstate transportation service and the West Virginia Public Service Commission (WVPSC) for intrastate transportation service. 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 and the WVPSC. 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.

Approximately 70% 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 at index-based prices under month-to-month contracts, while industrial and utility sales generally are made under year-to-year contracts. Approximately one percent of East production is sold on fixed price contracts that typically renew annually.

GULF COAST REGION

Our development, exploitation, exploration and production activities in the Gulf Coast region are primarily concentrated in east and south Texas and north Louisiana. A regional office in Houston manages the operations. Principal producing intervals are in the Cotton Valley, Haynesville and James Lime formations in north Louisiana and east Texas and the Frio, Vicksburg and Wilcox formations in south Texas at depths ranging from 2,200 to 17,400 feet, with an average depth of approximately 10,900 feet.

Capital and exploration expenditures were $962.0 million for 2008, or 64% of our total 2008 capital and exploration expenditures, compared to $291.5 million for 2007, or 46% of our total 2007 capital and exploration expenditures. This increase in capital spending includes the $604.0 million paid for the east Texas acquisition. Of the total company year-over-year increase in capital and exploration expenditures, approximately 79% was attributable to an increase in the Gulf Coast region spending. For 2009, we have budgeted approximately $230 million for capital and exploration expenditures in the region. Our 2009 Gulf Coast drilling program will emphasize activity primarily in east Texas.

We had 844 wells (592.2 net) in the Gulf Coast region as of December 31, 2008, of which 633 wells are operated by us. Average daily production in 2008 was 104.1 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2008 was 34.6 Bcf and 585 Mbbls, respectively.

At December 31, 2008, we had 554.6 Bcfe of proved reserves (93% natural gas) in the Gulf Coast region, which represented 29% of our total proved reserves. Developed and undeveloped reserves made up 317.3 Bcfe and 237.3 Bcfe of the total proved reserves for the Gulf Coast region, respectively. While no properties are individually significant to our company as a whole, the Brachfield Southeast field in the Minden area and the Angie field in the County Line area, both in east Texas, are included in our ten largest fields based on percentage of our total company proved equivalent reserves and together contain approximately 20% of our total company proved equivalent reserves.

In 2008, we drilled 94 wells (63.9 net) in the Gulf Coast region, of which 83 wells (57.1 net) were development and extension wells. In 2009, we plan to drill 65 wells (47.4 net), primarily in east Texas, including the Minden and County Line fields.

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 70% of our natural gas sales volumes in the Gulf Coast region are sold at index-based prices under contracts with terms of one year or greater. The remaining 30% 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 2008, we produced and marketed approximately 1,598 barrels of crude oil/condensate/NGL per day in the Gulf Coast region at market responsive prices.

WEST REGION

Our activities in the West region, which is comprised of the Rocky Mountains and Mid-Continent areas, are managed by a regional office in Denver, Colorado. At December 31, 2008, we had 475.3 Bcfe of proved reserves (97% natural gas) in the West region, constituting 24% of our total proved reserves. Developed and undeveloped reserves made up 380.3 Bcfe and 95.0 Bcfe of the total proved reserves for the West region, respectively. While no properties are individually significant to our company as a whole, the Mocane-Laverne field in Oklahoma in the Mid-Continent area is included within our ten largest fields and contains approximately three percent of our total company proved equivalent reserves.

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 90% 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 nine percent of the natural gas production is sold under short-term arrangements at index-based prices, and the remaining one percent 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 2008, we produced and marketed approximately 451 barrels of crude oil/condensate/NGL per day in the West region at market responsive prices.

Rocky Mountains

Activities in the Rocky Mountains are concentrated in the Green River and Washakie Basins in Wyoming and Paradox Basin in Colorado. At December 31, 2008, we had 271.4 Bcfe of proved reserves (96% natural gas) in the Rocky Mountains area, or 14% of our total proved reserves.

Capital and exploration expenditures in the Rocky Mountains were $88.7 million for 2008, or six percent of our total 2008 capital and exploration expenditures, compared to $54.7 million for 2007, or nine percent of our total 2007 capital and exploration expenditures. For 2009, we have budgeted approximately $29 million for capital and exploration expenditures in the area.

We had 716 wells (329.4 net) in the Rocky Mountains area as of December 31, 2008, of which 372 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 4,200 to 14,375 feet, with an average depth of approximately 10,900 feet. Average net daily production in the Rocky Mountains during 2008 was 41.3 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2008 was 14.5 Bcf and 95 Mbbls, respectively.

In 2008, we drilled 49 wells (31.3 net) in the Rocky Mountains, of which 47 wells (30.8 net) were development wells. In 2009, we plan to drill 8 wells (5.9 net), primarily in Wyoming, including the Cow Hollow and Lincoln Road fields.

Mid-Continent

Our Mid-Continent activities are concentrated in the Anadarko Basin in southwest Kansas, Oklahoma and the panhandle of Texas. At December 31, 2008, we had 203.9 Bcfe of proved reserves (98% natural gas) in the Mid-Continent area, or 10% of our total proved reserves.

Capital and exploration expenditures were $60.3 million for 2008, or four percent of our total 2008 capital and exploration expenditures, compared to $54.5 million for 2007, or eight percent of our total 2007 capital and exploration expenditures. For 2009, we have budgeted approximately $10 million for capital and exploration expenditures in the area.

As of December 31, 2008, we had 844 wells (594.5 net) in the Mid-Continent area, of which 659 wells are operated by us. Principal producing intervals in the Mid-Continent are in the Chase, Morrow and Chester formations at depths ranging from 2,200 to 17,450 feet, with an average depth of approximately 7,050 feet. Average net daily production in 2008 was 33.9 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2008 was 12.0 Bcf and 70 Mbbls, respectively.

In 2008, we drilled 71 wells (50.6 net) in the Mid-Continent, all of which were development and extension wells. In 2009, we plan to drill 12 wells (6.1 net), primarily in Oklahoma, including the Gage and Cederdale Northeast fields.

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 Province of Alberta. At December 31, 2008, we had 40.3 Bcfe of proved reserves (97% natural gas) in the Canada region, constituting two percent of our total proved reserves. Developed and undeveloped reserves made up 37.5 Bcfe and 2.8 Bcfe of the total proved reserves for the Canada region, respectively. No properties in the Canada region are individually significant to our company as a whole. The largest field in this region is the Hinton field in Alberta, which is not included in our ten largest fields.

Capital and exploration expenditures in Canada were $25.4 million for 2008, or two percent of our total 2008 capital and exploration expenditures, compared to $55.1 million for 2007, or nine percent of our total 2007 capital and exploration expenditures. For 2009, we have budgeted approximately $1 million for capital and exploration expenditures in the area.

We had 43 wells (16.2 net) in the Canada region as of December 31, 2008, of which 25 wells are operated by us. Principal producing intervals in the Canada region are in the Falher, Bluesky, Cadomin, Dunvegan and the Mountain Park formations at depths ranging from 8,500 to 14,500 feet, with an average depth of approximately 11,050 feet. Average net daily production in Canada during 2008 was 11.7 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2008 was 4.1 Bcf and 21 Mbbls, respectively.

In 2008, we drilled six wells (3.4 net) in Canada, of which four wells (2.6 net) were development and extension wells. In 2009, we do not plan to drill any wells in Canada.

Our principal markets for Canada natural gas are in western Alberta. We sell natural gas to gas marketers. Currently, all of our natural gas production in Canada is sold primarily under contracts with a term of one year at index-based prices. The Canadian properties are connected to the major interstate pipelines.

In 2008, we produced and marketed approximately 59 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 2008 we employed natural gas and crude oil price collar and swap agreements for portions of our 2008 through 2010 production to attempt to manage price risk more effectively. In 2007 and 2006, we primarily employed price collars to hedge our price exposure on our production. 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 falls below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas for the period is greater or less than the fixed price established for that period when the swap is put in place.

For 2008, collars covered 60% of natural gas production and had a weighted-average floor of $8.53 per Mcf and a weighted-average ceiling of $10.70 per Mcf. At December 31, 2008, natural gas price collars for the year ending December 31, 2009 will cover 47,253 Mmcf of production at a weighted-average floor of $9.40 per Mcf and a weighted-average ceiling of $12.39 per Mcf. For 2008, collars covered 47% of crude oil production and had a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl.

For 2008, swaps covered 11% of natural gas production and had a weighted-average price of $10.27 per Mcf. At December 31, 2008, natural gas price swaps for the years ending December 31, 2009 and 2010 will cover 16,079 Mmcf and 19,295 Mmcf of production, respectively, at a weighted-average price of $12.18 per Mcf and $11.43 per Mcf, respectively. For 2008, a swap covered 12% of crude oil production and had a fixed price of $127.15 per Bbl. Crude oil price swaps for the years ending December 31, 2009 and 2010 will cover 365 Mbbls each at a fixed price of $125.25 per Bbl and $125.00 per Bbl, respectively. Our decision to hedge 2009 and 2010 production fits with our risk management strategy and allows us to lock in the benefit of high commodity prices on a portion of our anticipated production. During January 2009, we entered into basis swaps in the Gulf Coast region that will cover 16,079 Mmcf of anticipated 2012 natural gas production at fixed basis differentials per Mcf of $(0.26) to $(0.27).

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" and "Quantitative and Qualitative Disclosures about Market Risk" for further discussion concerning our use of derivatives.

RESERVES

Current Reserves

The following table presents our estimated proved reserves at December 31, 2008.

	Natural Gas (Mmcf)			Liquids[1] (Mbbl)			Total[2] (Mmcfe)		
	Developed	**Undeveloped**	**Total**	**Developed**	**Undeveloped**	**Total**	**Developed**	**Undeveloped**	**Total**
East	611,284	258,379	869,663	355	—	355	613,412	258,379	871,791
Gulf Coast	292,626	223,446	516,072	4,114	2,306	6,420	317,311	237,280	554,591
Rocky Mountains	194,117	67,817	261,934	1,296	279	1,575	201,893	69,491	271,384
Mid-Continent	173,726	25,426	199,152	784	5	789	178,426	25,458	203,884
Canada	36,402	2,770	39,172	179	23	202	37,479	2,908	40,387
Total	**1,308,155**	**577,838**	**1,885,993**	**6,728**	**2,613**	**9,341**	**1,348,521**	**593,516**	**1,942,037**

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

(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 we have an effective system for gathering data and documenting information required to estimate our proved reserves and project our future revenues; we used appropriate engineering, geologic and evaluation principles and techniques in accordance with practices generally accepted in the petroleum industry in making our estimates and projections and 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. During 2008, we filed estimates of our oil and gas reserves for the year 2007 with the Department of Energy. These estimates differ by five percent or less from the reserve data presented. 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 2008.

For additional information about the risks inherent in our estimates of proved reserves, see “Risk Factors—Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated” in Item 1A.

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, 2005	1,262,096	11,463	1,330,874
Revision of Prior Estimates[2]	(17,675)	673	(13,640)
Extensions, Discoveries and Other Additions	246,197	1,066	252,594
Production	(79,722)	(1,415)	(88,212)
Purchases of Reserves in Place	1,946	38	2,176
Sales of Reserves in Place	(44,549)	(3,852)	(67,663)
December 31, 2006	1,368,293	7,973	1,416,129
Revision of Prior Estimates	2,604	771	7,228
Extensions, Discoveries and Other Additions	265,830	1,381	274,114
Production	(80,475)	(830)	(85,451)
Purchases of Reserves in Place	3,701	33	3,899
Sales of Reserves in Place	—	—	—
December 31, 2007	1,559,953	9,328	1,615,919
Revision of Prior Estimates[2]	(47,745)	(1,593)	(57,302)
Extensions, Discoveries and Other Additions	297,089	1,134	303,895
Production	(90,425)	(794)	(95,191)
Purchases of Reserves in Place	167,262	1,268	174,872
Sales of Reserves in Place	(141)	(2)	(156)
December 31, 2008	**1,885,993**	**9,341**	**1,942,037**
Proved Developed Reserves			
December 31, 2005	944,897	9,127	999,661
December 31, 2006	996,850	5,895	1,032,222
December 31, 2007	1,133,937	7,026	1,176,091
December 31, 2008	**1,308,155**	**6,728**	**1,348,521**

(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.

(2) The majority of the revisions were the result of the decrease in the natural gas price.

Volumes and Prices: Production Costs

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

	Year Ended December 31,		
	2008	**2007**	**2006**
Net Wellhead Sales Volume			
Natural Gas *(Bcf)*			
East	**25.2**	24.4	23.5
Gulf Coast	**34.6**	26.8	30.0
West	**26.5**	25.4	23.6
Canada	**4.1**	3.9	2.6
Crude/Condensate/Ngl *(Mbbl)*			
East	**23**	26	24
Gulf Coast	**585**	606	1,164
West	**165**	180	214
Canada	**21**	18	13
Produced Natural Gas Sales Price *($/Mcf)*(1)			
East	**$ 8.54**	$ 7.78	$ 7.99
Gulf Coast	**9.23**	8.03	7.37
West	**7.28**	6.13	6.05
Canada	**7.62**	5.47	6.18
Weighted-Average	**8.39**	7.23	7.13
Produced Crude/Condensate Sales Price *($/Bbl)*(1)			
East	**$92.07**	$66.97	$62.03
Gulf Coast	**87.39**	67.17	65.44
West	**95.48**	67.86	63.36
Canada	**85.08**	59.96	60.55
Weighted-Average	**89.11**	67.16	65.03
Production Costs *($/Mcfe)*(2)			
East	**$ 1.61**	$ 1.37	$ 1.12
Gulf Coast	**1.32**	1.44	1.37
West	**1.62**	1.27	1.34
Canada	**0.90**	0.84	0.84
Weighted-Average	**1.48**	1.36	1.31

(1) Represents the average realized sales price for all production volumes and royalty volumes sold during the periods shown, net of related costs (principally purchased gas royalty, transportation and storage). Includes realized impact of derivative instruments.

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

Acreage

The following tables summarize our gross and net developed and undeveloped leasehold and mineral acreage at December 31, 2008. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Leasehold Acreage by State						
Alabama	—	—	5,391	3,965	5,391	3,965
Arkansas	1,981	425	—	—	1,981	425
Colorado	16,267	14,053	175,627	119,839	191,894	133,892
Kansas	29,387	28,065	—	—	29,387	28,065
Louisiana	7,907	5,750	9,516	9,119	17,423	14,869
Maryland	—	—	1,662	1,662	1,662	1,662
Mississippi	—	—	421,639	278,270	421,639	278,270
Montana	397	210	143,473	107,910	143,870	108,120
New York	2,378	961	5,321	4,955	7,699	5,916
North Dakota	—	—	26,533	9,783	26,533	9,783
Ohio	6,246	2,384	2,403	1,214	8,649	3,598
Oklahoma	195,598	138,995	45,636	29,912	241,234	168,907
Pennsylvania	115,019	66,973	157,944	157,496	272,963	224,469
Texas	139,064	104,871	106,390	77,043	245,454	181,914
Utah	2,820	1,609	153,322	79,746	156,142	81,355
Virginia	7,167	5,040	2,508	1,454	9,675	6,494
West Virginia	602,313	570,282	259,708	228,127	862,021	798,409
Wyoming	140,143	72,443	151,327	85,102	291,470	157,545
Total	**1,266,687**	**1,012,061**	**1,668,400**	**1,195,597**	**2,935,087**	**2,207,658**
Mineral Fee Acreage by State						
Colorado	—	—	2,899	271	2,899	271
Kansas	160	128	—	—	160	128
Montana	—	—	589	75	589	75
New York	—	—	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	207	135	1,012	511	1,219	646
Virginia	17,817	17,817	100	34	17,917	17,851
West Virginia	98,162	79,490	50,896	49,669	149,058	129,159
Total	**133,450**	**112,073**	**64,344**	**52,594**	**197,794**	**164,667**
Aggregate Total	**1,400,137**	**1,124,134**	**1,732,744**	**1,248,191**	**3,132,881**	**2,372,325**

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Canada Leasehold Acreage by Province						
Alberta	16,160	7,669	70,240	24,860	86,400	32,529
British Columbia	700	280	11,283	2,606	11,983	2,886
Saskatchewan	—	—	4,549	—	4,549	—
Total	**16,860**	**7,949**	**86,072**	**27,466**	**102,932**	**35,415**

Total Net Leasehold Acreage by Region of Operation

	Developed	Undeveloped	Total
East	645,640	394,908	1,040,548
Gulf Coast	83,769	368,269	452,038
West	282,652	432,420	715,072
Canada	7,949	27,466	35,415
Total	**1,020,010**	**1,223,063**	**2,243,073**

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, 2008. The figures below assume no future successful development or renewal of undeveloped acreage.

	2009	2010	2011
East	44,302	37,148	85,838
Gulf Coast	69,260	187,803	61,761
West	63,089	113,296	67,884
Canada	6,982	898	320
Total	**183,633**	**339,145**	**215,803**

Well Summary

The following table presents our ownership at December 31, 2008, in productive natural gas and oil wells in the East region (consisting primarily of various fields located in West Virginia and Pennsylvania), 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, Utah and Wyoming) and in the Canada region (consisting of various fields located in the Province of Alberta). 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
East	3,355	3,149.2	27	13.4	3,382	3,162.6
Gulf Coast	721	481.2	123	111.0	844	592.2
West	1,505	890.5	55	33.4	1,560	923.9
Canada	42	15.6	1	0.6	43	16.2
Total	**5,623**	**4,536.5**	**206**	**158.4**	**5,829**	**4,694.9**

(1) Total does not include service wells of 54 (52.2 net).

Drilling Activity

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

	Year Ended December 31, 2008									
	East		Gulf Coast		West		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells										
Successful	203	196.4	78	52.3	114	78.2	3	2.0	398	328.9
Dry	1	1.0	4	3.8	3	2.5	1	0.6	9	7.9
Extension Wells										
Successful	3	3.0	1	1.0	1	0.7	—	—	5	4.7
Dry	1	1.0	—	—	—	—	—	—	1	1.0
Exploratory Wells										
Successful	3	3.0	11	6.8	—	—	2	0.8	16	10.6
Dry	1	1.0	—	—	2	0.5	—	—	3	1.5
Total	**212**	**205.4**	**94**	**63.9**	**120**	**81.9**	**6**	**3.4**	**432**	**354.6**
Wells Acquired	—	—	70	68.3	—	—	—	—	70	68.3
Wells in Progress at End of Year	5	4.8	6	4.1	4	2.4	—	—	15	11.3

	Year Ended December 31, 2007									
	East		Gulf Coast		West		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells										
Successful	248	238.8	80	61.0	96	63.1	5	2.8	429	365.7
Dry	1	1.0	3	2.5	7	5.8	—	—	11	9.3
Extension Wells										
Successful	1	1.0	4	3.0	—	—	3	1.2	8	5.2
Dry	—	—	—	—	—	—	—	—	—	—
Exploratory Wells										
Successful	3	2.8	1	0.5	—	—	2	1.2	6	4.5
Dry	1	1.0	4	4.0	2	1.2	—	—	7	6.2
Total	**254**	**244.6**	**92**	**71.0**	**105**	**70.1**	**10**	**5.2**	**461**	**390.9**
Wells Acquired	—	—	1	0.9	1	1.0	—	—	2	1.9
Wells in Progress at End of Year	2	2.0	9	5.2	2	1.1	1	0.2	14	8.5

	Year Ended December 31, 2006									
	East		Gulf Coast		West		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells										
Successful	195	186.0	40	29.8	107	56.0	5	2.7	347	274.5
Dry	2	2.0	2	1.9	3	2.3	1	0.2	8	6.4
Extension Wells										
Successful	—	—	10	9.7	1	0.1	—	—	11	9.8
Dry	—	—	—	—	—	—	1	0.7	1	0.7
Exploratory Wells										
Successful	2	2.0	8	6.2	—	—	2	0.8	12	9.0
Dry	1	0.7	4	3.2	2	1.7	1	1.0	8	6.6
Total	**200**	**190.7**	**64**	**50.8**	**113**	**60.1**	**10**	**5.4**	**387**	**307.0**
Wells Acquired	5	5.0	—	—	—	—	1	0.4	6	5.4
Wells in Progress at End of Year	—	—	4	3.9	1	0.5	2	1.3	7	5.7

Competition

Competition in our primary producing areas is intense. Price, contract terms and quality of service, including pipeline connection times and distribution efficiencies, affect competition. We believe that in the East region our extensive acreage position, existing natural gas gathering and pipeline systems, services and equipment that we have secured for the upcoming year and storage fields enhance our competitive position over other producers who do not have similar systems or facilities in place. We also actively compete against other companies with substantially larger financial and other resources.

OTHER BUSINESS MATTERS

Major Customer

In 2008, one customer accounted for approximately 16% of our total sales. In 2007 and 2006, no customer accounted for more than 10% of our total sales.

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 (NGA), 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. In addition, under the provisions of the Energy Policy Act of 2005, the NGA has been amended to prohibit any forms of market manipulation in connection with the purchase or sale of natural gas. Pursuant to the 2005 Act, the FERC established new regulations that are intended to increase natural gas pricing transparency through, among other things, requiring market participants to report their gas sales transactions annually to the FERC, and new regulations that require certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points on their systems. The 2005 Act also significantly increased the penalties for violations of the NGA and the FERC's regulations.

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 established regulations governing the relationship of pipelines with their marketing affiliates, which essentially require that designated employees function independently of each other, and that certain information not be shared. The FERC has also 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 (2002 Act), 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 and non-rural gathering pipeline facilities within the next ten years, and at least every seven years thereafter. On March 15, 2006, the DOT revised these regulations to define more clearly the categories of gathering facilities subject to DOT regulation, establish new safety rules for certain gathering lines in rural areas, revise the current regulations applicable to safety and inspection of gathering lines in non-rural areas, and adopt new compliance deadlines. We have completed 100% of the required initial inspection (baseline assessment) of our pipeline systems in West Virginia. In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, which reauthorized the programs adopted under the 2002 Act, proposed enhancements for state programs to reduce excavation damage to pipelines, established increased federal enforcement of one-call excavation programs, and established a new program for review of pipeline security plans and critical facility inspections. In September 2008, as mandated by this statute, DOT issued a Notice of Proposed Rulemaking to establish new rules that would require pipeline operators to amend their existing written operations and maintenance procedures, operator qualification programs, and emergency plans, to assure pipeline safety and integrity. We are not able to predict with certainty the final outcome of these rules on our facilities or our business.

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. 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. In March 2006, to implement this required five-year re-determination, the FERC established an upward adjustment in the index to track oil pipeline cost changes and determined that the Producer Price Index for Finished Goods plus 1.3 percent should be the oil pricing index for the five-year period beginning July 1, 2006. Another FERC matter that may impact our transportation costs relates to a recent policy that allows a pipeline structured as a master limited partnership or similar non-corporate entity to include in its rates a tax allowance with respect to income for which there is an "actual or potential income tax liability," to be determined on a case by case basis. Generally speaking, where the holder of a partnership unit interest is required to file a tax return that includes partnership income or loss, such unit-holder is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income.

We are not able to predict with certainty the effect upon us of these periodic reviews by the FERC of the pipeline index, or of the application of the FERC's policy on income tax allowances.

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, and can affect the timing of 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.

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 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 treated or disposed of or arranged for the treatment or 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 used materials and generated wastes and will continue to use materials and 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 substances have been released.

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 (Clean Water Act) and resulting regulations, which are primarily 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 or to cease hauling wastewaters to facilities owned by others 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 or to install additional controls on 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, 2008, we had 560 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 reports 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 or furnished to the Securities and Exchange Commission (SEC). Information on our website is not a part of this report. In addition, the SEC maintains an Internet site at *www.sec.gov* that contains reports, proxy and information statements and other information filed by the Company. The public may read and copy materials that we file with the SEC at the SEC's Public Reference Room located at 100 F Street, NE, Washington, DC 20549. Information regarding the operation of the Public Reference Room can be obtained by calling the SEC at 1-800-SEC-0330.

Corporate Governance Matters

The Company's Corporate Governance Guidelines, Corporate Bylaws, 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 of "Investor Relations" and a copy will be provided, without charge, to any shareholder upon request. Requests can also be made in writing to Investor Relations at our corporate headquarters at 1200 Enclave Parkway, Houston, Texas, 77077. We have filed the required certifications of our chief executive officer and our chief financial officer under Section 302 of the Sarbanes-Oxley Act of 2002 as exhibits 31.1 and 31.2 to this Form 10-K. In 2008, we submitted to the New York Stock Exchange the chief executive officer certification required by Section 303A.12(a) of the NYSE's Listed Company Manual.

ITEM 1A. RISK FACTORS

Natural gas and oil 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. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Natural gas price have declined from approximately $13 per Mmbtu in July 2008 to approximately $4.50 per Mmbtu as of February 1, 2009. Oil prices have declined from record levels in July 2008 of approximately $145 per barrel to approximately $40 per barrel as of February 1, 2009. Depressed prices in the future would have a negative impact on our future financial results. Because our reserves are predominantly natural gas, changes in natural gas prices have a particularly large impact on our financial results.

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

- the level of consumer product demand;
- weather conditions;
- political conditions in natural gas and 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;
- pipeline availability and capacity constraints;
- inventory storage levels;
- domestic and foreign governmental regulations;
- the price, availability and acceptance of alternative fuels; and
- overall economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. If natural gas prices decline significantly for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

Drilling natural gas and oil wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors beyond our control, including:

- unexpected drilling conditions, pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate for activity within a particular geographic area may decline. We may ultimately not be able to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may not be able to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects.

These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive natural gas or oil.

Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated.

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

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and crude oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board in Statement of Financial Accounting Standards No. 69 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable.

In general, the production rate of natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in natural gas and oil production and lower revenues and cash flow from operations. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Low natural gas and oil prices may further limit the kinds of reserves that we can develop economically. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

Our reserve report estimates that production from our proved developed producing reserves as of December 31, 2008 will decline at estimated rates of 21%, 17%, 12% and 11% during 2009, 2010, 2011 and 2012, respectively. Future development of proved undeveloped and other reserves currently not classified as proved developed producing will impact these rates of decline. Because of higher initial decline rates from newly developed reserves, we consider this pattern fairly typical.

Exploration, development and exploitation activities involve numerous risks that may result in dry holes, the failure to produce natural gas and oil in commercial quantities and the inability to fully produce discovered reserves.

Acquired properties may not be worth what we pay due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include exploration potential, future natural gas and oil prices, operating costs, and potential environmental and other liabilities. These assessments are complex and inherently imprecise. Our review of the properties we acquire may not reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, and our contractual indemnification may not be effective. Often, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties.

The integration of the properties we acquire could be difficult, and may divert management's attention away from our existing operations.

The integration of the properties we acquire could be difficult, and may divert management's attention and financial resources away from our existing operations. These difficulties include:

- the challenge of integrating the acquired properties while carrying on the ongoing operations of our business; and
- the possibility of faulty assumptions underlying our expectations.

The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our existing business. If management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

We face a variety of hazards and risks that could cause substantial financial losses.

Our business involves a variety of operating risks, including:

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

In addition, we conduct operations in shallow offshore areas (largely coastal waters), which are subject to additional hazards of marine operations, such as capsizing, collision and damage from severe weather. Any of these events could result in injury or loss of human life, loss of hydrocarbons, significant damage to or destruction of property, environmental pollution, regulatory investigations and penalties, impairment of our operations and substantial losses to us.

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. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites, could increase these risks. As of December 31, 2008, we owned or operated approximately 3,500 miles of natural gas gathering and pipeline systems. As part of our normal maintenance program, we have identified certain segments of our pipelines that we believe periodically require repair, replacement or additional maintenance.

We may not be insured against all of the operating risks to which we are exposed.

We maintain insurance against some, but not all, of these risks and losses. We do not carry business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. Non-operated wells represented approximately 15% of our total owned gross wells, or approximately 4.8% of our owned net wells, as of December 31, 2008. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Our ability to sell our natural gas and oil production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

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

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record. Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry.

We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of increases in prices for natural gas and oil.

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 2008 we employed natural gas and crude oil price collar and swap agreements covering portions of our 2008 production and anticipated 2009 and 2010 production to attempt to manage price risk more effectively. 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 falls below the floor. 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. These hedging arrangements limit the benefit to us of increases in prices. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty is unable to satisfy its obligations;
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

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” in Item 7 and “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A for further discussion concerning our use of derivatives.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is extremely intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to extensive federal, state and local laws and regulations, including tax laws and regulations and those relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These laws and regulations can adversely affect the cost, manner or feasibility of doing business. Many laws and regulations require permits for the operation of various facilities, and these permits are subject to revocation, modification and renewal. Governmental authorities have the power to enforce compliance with their regulations, and violations could subject us to fines, injunctions or both. These laws and regulations have increased the costs of planning, designing, drilling, installing and operating natural gas and oil facilities. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. Risks of substantial costs and liabilities related to environmental compliance issues are inherent in natural gas and oil operations. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from natural gas and oil production, would result in substantial costs and liabilities.

Provisions of Delaware law and our bylaws and charter could discourage change in control transactions and prevent stockholders from receiving a premium on their investment.

Our bylaws provide for a classified Board of Directors with staggered terms, and our charter authorizes our Board of Directors to set the terms of preferred stock. In addition, Delaware law contains provisions that impose restrictions on business combinations with interested parties. Our bylaws prohibit stockholder action by written consent and limit stockholder proposals at meetings of stockholders. We also have adopted a stockholder rights plan. Because of our stockholder rights plan and these provisions of our charter, bylaws and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our Board of Directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our stockholders to benefit from transactions that are opposed by an incumbent Board of Directors.

The personal liability of our directors for monetary damages for breach of their fiduciary duty of care is limited by the Delaware General Corporation Law and by our certificate of incorporation.

The Delaware General Corporation Law allows corporations to limit available relief for the breach of directors' duty of care to equitable remedies such as injunction or rescission. Our certificate of incorporation limits the liability of our directors to the fullest extent permitted by Delaware law. Specifically, our directors will not be personally liable for monetary damages for any breach of their fiduciary duty as a director, except for liability:

- for any breach of their duty of loyalty to the company or our stockholders;
- for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law;
- under provisions relating to unlawful payments of dividends or unlawful stock repurchases or redemptions; and
- for any transaction from which the director derived an improper personal benefit.

This limitation may have the effect of reducing the likelihood of derivative litigation against directors, and may discourage or deter stockholders or management from bringing a lawsuit against directors for breach of their duty of care, even though such an action, if successful, might otherwise have benefited our stockholders.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, market conditions could have an impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, the current economic situation could lead to further reduced demand for oil and natural gas, or lower prices for oil and natural gas, or both, which could have a negative impact on our revenues.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

See Item 1. "Business."

ITEM 3. LEGAL PROCEEDINGS

We are a defendant in various legal proceedings arising in the normal course of our business. All known liabilities are accrued based on management's best estimate of the potential loss. While the outcome and impact of such legal proceedings 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 or cash flow. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Commitment and Contingency Reserves

When deemed necessary, we establish 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 $2.1 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 or cash flow. Operating results, 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 2008.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information as of February 15, 2009 about our executive officers, 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	55	Chairman, President and Chief Executive Officer	2001
Michael B. Walen	60	Senior Vice President, Chief Operating Officer	1998
Scott C. Schroeder	46	Vice President and Chief Financial Officer	1997
J. Scott Arnold	55	Vice President, Land and General Counsel	1998
Robert G. Drake	61	Vice President, Information Services and Operational Accounting	1998
Abraham D. Garza	62	Vice President, Human Resources	1998
Jeffrey W. Hutton	53	Vice President, Marketing	1995
Thomas S. Liberatore	52	Vice President, Regional Manager, East Region	2003
Lisa A. Machesney	53	Vice President, Managing Counsel and Corporate Secretary	1995
Henry C. Smyth	62	Vice President, Controller and Treasurer	1998

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

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our 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 our 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. A regular dividend has been declared each quarter since we became a public company in 1990.

On February 23, 2007, our Board of Directors declared a 2-for-1 split of our common stock in the form of a stock distribution. The stock dividend was distributed on March 30, 2007 to stockholders of record on March 16, 2007. All common stock accounts and per share data, including cash dividends per share, have been retroactively adjusted to give effect to the 2-for-1 split of our common stock. After the stock split, the dividend was increased to $0.03 per share per quarter, or a 50% increase from pre-split levels.

	High	Low	Dividends
2008			
First Quarter	**$53.41**	**$37.67**	**$0.03**
Second Quarter	**$71.11**	**$51.48**	**$0.03**
Third Quarter	**$68.58**	**$33.58**	**$0.03**
Fourth Quarter	**$33.83**	**$21.31**	**$0.03**
2007			
First Quarter	$35.29	$28.06	$0.02
Second Quarter	$41.88	$34.55	$0.03
Third Quarter	$38.39	$31.55	$0.03
Fourth Quarter	$40.90	$33.59	$0.03

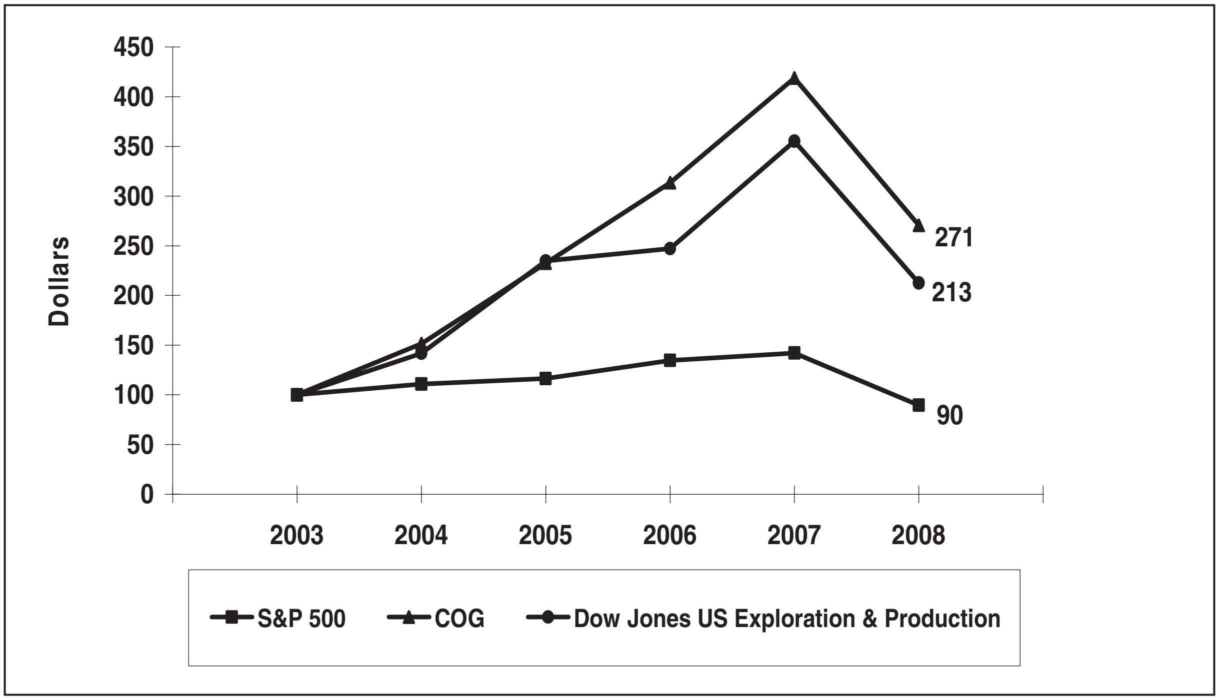
As of January 31, 2009, there were 544 registered holders of the common stock. Shareholders include individuals, brokers, nominees, custodians, trustees, and institutions such as banks, insurance companies and pension funds. Many of these hold large blocks of stock on behalf of other individuals or firms.

ISSUER PURCHASES OF EQUITY SECURITIES

Our Board of Directors has authorized a share repurchase program under which we may purchase shares of common stock in the open market or in negotiated transactions. There is no expiration date associated with the authorization. During 2008, we did not repurchase any shares of common stock. All purchases executed to date have been through open market transactions. The maximum number of shares that may yet be purchased under the plan as of December 31, 2008 was 4,795,300.

PERFORMANCE GRAPH

The following graph compares our common stock performance ("COG") with the performance of the Standard & Poors' 500 Stock Index and the Dow Jones US Exploration & Production Index for the period December 2003 through December 2008. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2003 and that all dividends were reinvested.



Calculated Values	2003	2004	2005	2006	2007	2008
S&P 500	100.0	110.9	116.3	134.7	142.1	89.5
COG	100.0	151.4	232.4	313.5	418.7	270.5
Dow Jones US Exploration & Production	100.0	141.9	234.5	247.1	355.1	212.6

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

ITEM 6. SELECTED FINANCIAL DATA

The following table summarizes our selected consolidated financial data for the periods indicated. This information should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7, and the Consolidated Financial Statements and related Notes in Item 8.

	Year Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
	(In thousands, except per share amounts)				
Statement of Operations Data					
Operating Revenues	**$ 945,791**	$ 732,170	$ 761,988	$ 682,797	$ 530,408
Impairment of Oil & Gas Properties and Other Assets(1)	**35,700**	4,614	3,886	—	3,458
Gain / (Loss) on Sale of Assets(2)	**1,143**	13,448	232,017	74	(124)
Gain on Settlement of Dispute(3)	**51,906**	—	—	—	—
Income from Operations	**372,012**	274,693	528,946	258,731	160,653
Net Income	**211,290**	167,423	321,175	148,445	88,378
Basic Earnings per Share(4)	**$ 2.10**	$ 1.73	$ 3.32	$ 1.52	$ 0.91
Diluted Earnings per Share(4)	**$ 2.08**	$ 1.71	$ 3.26	$ 1.49	$ 0.90
Dividends per Common Share(4)	**$ 0.120**	$ 0.110	$ 0.080	$ 0.074	$ 0.054
Balance Sheet Data					
Properties and Equipment, Net	**$3,135,828**	$1,908,117	$1,480,201	$1,238,055	$ 994,081
Total Assets	**3,701,664**	2,208,594	1,834,491	1,495,370	1,210,956
Current Portion of Long-Term Debt	**35,857**	20,000	20,000	20,000	20,000
Long-Term Debt	**831,143**	330,000	220,000	320,000	250,000
Stockholders' Equity	**1,790,562**	1,070,257	945,198	600,211	455,662

(1) For discussion of impairment of oil and gas properties and other assets, refer to Note 2 of the Notes to the Consolidated Financial Statements.

(2) Gain on Sale of Assets for 2007 and 2006 reflects $12.3 million and $231.2 million, respectively, related to disposition of our offshore portfolio and certain south Louisiana properties (the "2006 south Louisiana and offshore properties sale"), which was substantially completed in the third quarter of 2006.

(3) Gain on Settlement of Dispute is associated with the Company's settlement of a dispute in the fourth quarter of 2008. The dispute settlement includes the value of cash and properties received. See Note 7 of the Notes to the Consolidated Financial Statements.

(4) All Earnings per Share and Dividends per Common Share figures have been retroactively adjusted for the 2-for-1 split of our common stock effective March 31, 2007 as well as the 3-for-2 split of our common stock effective March 31, 2005.

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 to the Consolidated Financial Statements 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" for further details.

We operate in one segment, natural gas and oil development, exploitation and exploration, exclusively within the United States and Canada.

OVERVIEW

Cabot Oil & Gas and its subsidiaries are a leading independent oil and gas company engaged in the development, exploitation, exploration, production and marketing of natural gas, and to a lesser extent, crude oil and natural gas liquids from its properties in North America. We also transport, store, gather and produce natural gas for resale. Our exploitation and 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 compete for available capital: drilling opportunities, financial opportunities such as debt repayment or repurchase of common stock and acquisition opportunities. 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. At any one time, one or more of these may not be economically feasible.

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 2007 and most of 2008, the futures market reported strong natural gas and crude oil contract prices. During the fourth quarter of 2008, commodity prices experienced a sharp decline. Our realized natural gas and crude oil price was $8.39 per Mcf and $89.11 per Bbl, respectively, in 2008. These realized prices include the realized impact of derivative instruments. In an effort to manage commodity price risk, we entered into a series of crude oil and natural gas price swaps and collars. These financial instruments are an important element of our risk management strategy and assisted in the increase in our realized natural gas price from 2007 to 2008.

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 supply and demand, 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, NGL and crude oil prices and, therefore, we cannot determine with any degree of certainty 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. See “Risk Factors—Natural gas and oil prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business” and “Risk Factors—Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable” in Item 1A.

The tables below illustrate how natural gas prices have fluctuated by month over 2007 and 2008. “Index” represents the first of the month Henry Hub index price per Mmbtu. The “2007” and “2008” 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:

Natural Gas Prices by Month - 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	**$7.13**	**$8.01**	**$8.96**	**$9.59**	**$11.29**	**$11.93**	**$13.11**	**$9.23**	**$8.40**	**$7.48**	**$6.47**	**$6.90**
2008	**$7.46**	**$7.82**	**$8.45**	**$9.03**	**$ 9.38**	**$ 9.50**	**$ 9.36**	**$8.61**	**$8.05**	**$7.89**	**$7.70**	**$7.54**

Natural Gas Prices by Month - 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$5.84	$6.93	$7.55	$7.56	$ 7.51	$ 7.59	$ 6.93	$6.11	$5.43	$6.43	$7.27	$7.21
2007	$7.05	$7.61	$7.63	$7.04	$ 7.30	$ 7.38	$ 7.05	$6.94	$6.41	$7.06	$7.44	$7.87

Prices for crude oil maintained strength in 2007 and rose to record high levels in 2008, but experienced significant declines in the fourth quarter of 2008. The tables below contain the NYMEX monthly average crude oil price (Index) and our realized per barrel (Bbl) crude oil prices by month for 2007 and 2008. The "2007" and "2008" price is the crude oil price per Bbl realized by us and includes the realized impact of our crude oil derivative arrangements:

Crude Oil Prices by Month - 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	**$92.93**	**$95.35**	**$105.42**	**$112.46**	**$125.46**	**$134.02**	**$133.48**	**$116.69**	**$103.76**	**$76.72**	**$57.44**	**$42.04**
2008	**$83.71**	**$85.02**	**$ 90.85**	**$ 92.56**	**$ 99.79**	**$103.83**	**$102.76**	**$101.16**	**$ 93.51**	**$87.10**	**$69.16**	**$62.45**

Crude Oil Prices by Month - 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$54.67	$59.39	$ 60.74	$ 64.04	$ 63.53	$ 67.53	$ 74.15	$ 72.36	$ 79.63	$85.66	$94.63	$91.74
2007	$51.59	$53.17	$ 55.54	$ 61.31	$ 63.35	$ 61.42	$ 70.68	$ 70.03	$ 71.90	$83.97	$84.38	$82.65

We reported earnings of $2.10 per share, or $211.3 million, for 2008, an increase from the $1.73 per share, or $167.4 million, reported in 2007. Natural gas revenues increased from 2007 to 2008 as a result of favorable natural gas hedge settlements, increased commodity market prices and increased natural gas production. Crude oil revenues increased from 2007 to 2008 primarily due to increased realized prices, partially offset by a reduction in crude oil production. Prices, including the realized impact of derivative instruments, increased by 16% for natural gas and 33% for oil.

We drilled 432 gross wells with a success rate of 97% in 2008 compared to 461 gross wells with a success rate of 96% in 2007. Total capital and exploration expenditures increased by $844.8 million to $1,481.0 million (including the east Texas acquisition) in 2008 compared to $636.2 million in 2007. We believe our cash on hand and operating cash flow in 2009 will be sufficient to fund our budgeted capital and exploration spending of approximately $475 million. Any additional needs will be funded by borrowings from our credit facility. We have reduced, and may continue to reduce, our budgeted capital and exploration spending to maintain sufficient liquidity.

Our 2009 strategy will remain consistent with 2008. We will remain focused on our strategies of pursuing lower risk drilling opportunities that provide more predictable results on our accumulated acreage position. Additionally, we intend to manage our balance sheet in an effort to ensure that we have sufficient liquidity, and we intend to maintain spending discipline. In the current year we have allocated our planned program for capital and exploration expenditures primarily to the East and Gulf Coast regions. We believe these strategies are appropriate for our portfolio of projects and the current industry environment and that this activity will continue to add shareholder value over the long-term.

The preceding paragraphs, discussing our strategic pursuits and goals, contain forward-looking information. Please read "Forward-Looking Information" for further details.

FINANCIAL CONDITION

Capital Resources and Liquidity

Our primary sources of cash in 2008 were from funds generated from the sale of natural gas and crude oil production, the private placements of debt completed in July and December 2008, the sale of common stock and, to a lesser extent, borrowings under our revolving credit facility and asset sales. Cash flows provided by operating activities, borrowings, the sale of common stock and proceeds from asset sales were primarily used to fund our development (including acquisitions) and, to a lesser extent, exploratory expenditures, in addition to paying dividends and debt issuance costs. See below for additional discussion and analysis of cash flow.

We generate 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 volatile, including seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have also influenced prices throughout the recent years. Commodity prices have recently experienced increased volatility due to adverse market conditions in our economy. In addition, fluctuations 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.

Our working capital is also substantially influenced by variables discussed above. From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. This fluctuation is not unusual. The recent financial and credit crisis has reduced credit availability and liquidity for some companies; however, we believe we have adequate liquidity available to meet our working capital requirements.

	Year Ended December 31,		
	2008	**2007**	**2006**
		(In thousands)	
Cash Flows Provided by Operating Activities	**$ 634,447**	$ 462,137	$ 357,104
Cash Flows Used in Investing Activities	**(1,452,289)**	(589,922)	(187,353)
Cash Flows Provided by / (Used in) Financing Activities	**827,445**	104,429	(138,523)
Net Increase / (Decrease) in Cash and Cash Equivalents	**$ 9,603**	$ (23,356)	$ 31,228

Operating Activities. Key components impacting net operating cash flows are commodity prices, production volumes and operating costs. Net cash provided by operating activities in 2008 increased by $172.3 million over 2007. This increase was mainly due to an increase in net income, the receipt of cash of $20.2 million in 2008 in connection with the settlement of a dispute and an increase of $13.7 million in cash received for income tax refunds. In addition, cash flows from operating activities increased as a result of other working capital changes. Average realized natural gas prices increased by 16% in 2008 over 2007 and average realized crude oil prices increased by 33% over the same period. Equivalent production volumes increased by 11% in 2008 compared to 2007 as a result of higher natural gas production. 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. Realized prices may be lower in 2009.

Net cash provided by operating activities in 2007 increased by $105.0 million over 2006. This increase was mainly due to a decrease in cash paid for current income taxes from 2006 to 2007 primarily due to the 2006 payment of approximately $102 million related to the 2006 south Louisiana and offshore properties sale, as well as our 2007 tax net operating loss position and the receipt in 2007 of $29.6 million in federal tax refunds relating to our 2006 tax return. Average realized natural gas prices increased by one percent in 2007 over 2006 and average realized crude oil prices increased by three percent over the same period. Equivalent production decreased by three percent in 2007 compared to 2006 as a result of a decrease in crude oil production, offset in part by an increase in natural gas production.

See "Results of Operations" for a discussion on commodity prices and a review of the impact of prices and volumes on sales revenue.

Investing Activities. The primary uses of cash in investing activities were capital spending (including the east Texas acquisition and new leases in both Pennsylvania and east Texas) and exploration expenses. We established the budget for these amounts based on our current estimate of future commodity prices. Due to the volatility of commodity prices and new opportunities which may arise, our capital expenditures may be periodically adjusted during any given year. Cash flows used in investing activities increased by $862.4 million from 2007 to 2008 and increased by $402.6 million from 2006 to 2007. The increase from 2007 to 2008 was due to an increase of $866.0 million in capital expenditures, including an increase of approximately $601.8 million primarily due to the $604.0 million east Texas acquisition and an increase of $130.5 million related to unproved leasehold acquisitions primarily in northeast Pennsylvania. In addition, there were $5.0 million of lower proceeds from the sale of assets in 2008 compared to 2007. Partially offsetting these increases to cash used in investing activities were decreased exploration expenditures of $8.6 million in 2008 compared to 2007.

The increase in cash flows used in investing activities from 2006 to 2007 was due to a decrease of $322.4 million in 2007 in proceeds from the sale of assets and an increase of $89.8 million in 2007 in capital expenditures, partially offset by reduced exploration expenses of $9.6 million.

Financing Activities. Cash flows provided by financing activities increased by $723.0 million from 2007 to 2008. This was primarily due to an increase in debt consisting of our July 2008 and December 2008 private placements of debt ($492 million) and an increase of $45 million in borrowings under our revolving credit facility. Additionally, net proceeds from the sale of common stock increased by $311.1 million primarily due to the June 2008 issuance of common stock. The tax benefit for stock-based compensation increased by $10.7 million from 2007 to 2008, but was partially offset by an increase in dividends and capitalized debt issuance costs paid.

Cash flows provided by financing activities increased by $243.0 million from 2006 to 2007 primarily due to a $210.0 million increase in debt, principally related to higher borrowings under our revolving credit facility. In addition, $46.5 million of treasury stock was purchased in 2006 compared with none in 2007. Partially offsetting these increases in cash provided by financing activities were a $9.5 million reduction in the tax benefit for stock-based compensation, lower proceeds from the exercise of stock options and higher dividend payments.

At December 31, 2008, we had $185 million of borrowings outstanding under our unsecured credit facility at a weighted-average interest rate of 3.7%. In December 2008, the revolving credit facility was amended to extend the commitment period for lenders holding approximately 90% of the aggregate commitments from December 2009 to October 2010. The December amendment added an accordion feature to allow us, if the existing banks or new banks agree, to increase the available credit line from $350 million to $450 million. The available credit line is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the banks' petroleum engineer) and other assets. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. Management believes that we have the capacity to finance our spending plans and maintain our liquidity. At the same time, we will closely monitor the capital markets. As a result of market conditions and our increased level of borrowings, we may experience increased costs associated with future debt.

In July 2008, we completed a private placement of $425 million aggregate principal amount of senior unsecured fixed-rate notes with a weighted-average interest rate of 6.51%, consisting of amounts due in July 2018, 2020 and 2023. In December 2008, we completed a private placement of $67 million aggregate principal amount of senior unsecured 9.78% fixed-rate notes due in December 2018. Please refer to Note 4 of the Notes to the Consolidated Financial Statements for further details.

In June 2008, we entered into an underwriting agreement pursuant to which we sold an aggregate of 5,002,500 shares of common stock at a price to us of $62.66 per share. This aggregate share amount included 652,500 shares of common stock that were issued as a result of the exercise of the underwriters' option to purchase additional shares. We received $313.5 million in net proceeds, after deducting underwriting discounts and commissions. These net proceeds were used temporarily to reduce outstanding borrowings under our revolving credit facility prior to funding a portion of the purchase price of our east Texas acquisition, which closed in the third quarter of 2008. Immediately prior to (and in connection with) this issuance, we retired 5,002,500 shares of treasury stock, which had a weighted-average purchase price of $16.46.

Capitalization

Information about our capitalization is as follows:

	December 31, 2008	December 31, 2007
	(Dollars in millions)	
Debt[1]	**$ 867.0**	$ 350.0
Stockholders' Equity	**1,790.6**	1,070.3
Total Capitalization	**$2,657.6**	$1,420.3
Debt to Capitalization	**33%**	25%
Cash and Cash Equivalents	**$ 28.1**	$ 18.5

(1) Includes $35.9 million and $20.0 million of current portion of long-term debt at December 31, 2008 and 2007, respectively. Includes $185 million and $140 million of borrowings outstanding under our revolving credit facility at December 31, 2008 and 2007, respectively.

For the year ended December 31, 2008, we paid dividends of $12.1 million on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990. After the March 2007 2-for-1 stock split, the dividend was increased to $0.03 per share per quarter, or a 50% increase from pre-split levels.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital and exploration activities, excluding any significant 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, 2008.

	2008	2007	2006
		(In millions)	
Capital Expenditures			
Drilling and Facilities[1]	**$ 624.3**	$539.7	$405.5
Leasehold Acquisitions	**152.7**	22.2	42.6
Acquisitions	**625.0**	4.0	6.7
Pipeline and Gathering	**36.9**	28.2	24.2
Other	**10.9**	2.3	9.1
	1,449.8	596.4	488.1
Exploration Expense	**31.2**	39.8	49.4
Total	**$1,481.0**	$636.2	$537.5

(1) Includes Canadian currency translation effects of $(27.7) million, $15.0 million and $(1.4) million in 2008, 2007 and 2006, respectively.

We plan to drill approximately 148 gross wells (122.3 net) in 2009 compared with 432 gross wells (355 net) drilled in 2008. The number of wells we plan to drill in 2009 is down from 2008 in each of our operating regions due to the underlying economic fundamentals, which have significantly reduced commodity prices. This 2009 drilling program includes approximately $475 million in total capital and exploration expenditures, down from $1,481 million in 2008. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease the capital and exploration expenditures accordingly.

There are many factors that impact our depreciation, depletion and amortization (DD&A) rate. These include reserve additions and revisions, development costs, impairments and changes in anticipated production in future periods. In 2009, management expects an increase in our DD&A rate due to higher capital costs, partially as a result of inflationary cost pressures in the industry over the last four years. This change is currently estimated to be approximately 13% greater than 2008 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, firm gas transportation agreements, drilling rig commitments and operating leases. We have no off-balance sheet debt or other similar unrecorded obligations.

A summary of our contractual obligations as of December 31, 2008 are set forth in the following table:

		Payments Due by Year			
	Total	**2009**	**2010 to 2011**	**2012 to 2013**	**2014 & Beyond**
			(In thousands)		
Long-Term Debt[1]	**$ 867,000**	$ 35,857	$244,143	$ 75,000	$512,000
Interest on Long-Term Debt[2]	**460,624**	63,124	99,602	82,469	215,429
Firm Gas Transportation Agreements[3]	**94,670**	13,218	23,935	13,374	44,143
Drilling Rig Commitments[3]	**44,271**	42,021	2,250	—	—
Operating Leases[3]	**28,686**	6,335	9,028	7,397	5,926
Total Contractual Cash Obligations	**$1,495,251**	$160,555	$378,958	$178,240	$777,498

(1) Including current portion. At December 31, 2008, we had $185 million of debt outstanding under our revolving credit facility. See Note 4 of the Notes to the Consolidated Financial Statements for details of long-term debt.

(2) Interest payments have been calculated utilizing the fixed rates of our $682 million long-term debt outstanding at December 31, 2008. Interest payments on our revolving credit facility were calculated by assuming that the December 31, 2008 long-term outstanding balance of $169.1 million will be outstanding through the October 2010 maturity date and that the short-term outstanding balance of $15.9 million will be outstanding through December 2009. A constant interest rate of 4.8% was assumed, which was the 2008 weighted-average interest rate. Actual results will likely differ from these estimates and assumptions.

(3) For further information on our obligations under firm gas transportation agreements, drilling rig commitments and operating leases, see Note 7 of the Notes to the Consolidated Financial Statements.

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, 2008 was $28.0 million, up from $24.7 million at December 31, 2007, primarily due to $1.2 million of accretion expense during 2008 as well as $2.2 million of drilling additions.

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 imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as oil and gas prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds.

Since 1990, 100% of our reserves have been reviewed by Miller & Lents, Ltd., an independent oil and gas reservoir engineering consulting firm, who in their opinion determined the estimates presented to be reasonable in the aggregate. We have not been required to record a significant reserve revision in the past three years. For more information regarding reserve estimation, including historical reserve revisions, refer to the "Supplemental Oil and Gas Information."

Our rate of recording DD&A expense 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 $0.09 to $0.10 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 $0.05 to $0.06 impact on our total DD&A rate. These estimated impacts are based on current data, and actual events could require different adjustments to our DD&A rate.

In addition, a decline in proved reserve estimates may impact the outcome of our impairment test under Statement of Financial Accounting Standards (SFAS) No. 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 expected 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. The discount factor used (13% at December 31, 2008) is based on management's belief that this rate is commensurate with the risks inherent in the development and production of the underlying natural gas and oil. In 2008, 2007 and 2006, there were no unusual or unexpected occurrences that caused significant revisions in estimated cash flows which were utilized in our impairment test. In the event that commodity prices remain low or continue to decline, there could be a significant revision in the future.

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 life in each of the regions has not significantly changed. During the last six months of 2008, commodity prices declined at a significant rate as the global economy struggled with a worldwide recession. This price environment has resulted in reduced capital available for exploration projects as well as development drilling. We have considered these impacts discussed above when assessing the impairment of our undeveloped acreage, especially in exploratory areas. If the average unproved property life decreases or increases by one year, the amortization would increase by approximately $13.3 million or decrease by approximately $10.7 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 East, Gulf Coast and West regions have been five, four and seven 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

We follow the accounting prescribed in SFAS No. 133. Under SFAS No. 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 quarterly period, these instruments are marked-to-market. The gain or loss on the change in fair value is recorded as Accumulated Other Comprehensive Income, a component of equity, to the extent that the derivative instrument is designated as a hedge and is effective. Under SFAS No. 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. 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 in the Consolidated Statement of Operations.

Fair Value Measurements

Effective January 1, 2008, we adopted those provisions of SFAS No. 157, “Fair Value Measurements,” that were required to be adopted. This adoption did not have a material impact on any of our financial statements. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

We utilize market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We attempt to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. SFAS No. 157 establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to level 1 measurements and the lowest priority to level 3 measurements, and accordingly, level 1 measurements should be used whenever possible.

As of December 31, 2008, we had $355.2 million of assets, or 10% of our total assets, classified as Level 3. This was entirely comprised of our derivative receivable balance from our oil and gas cash flow hedges. During 2008, realized gains of $347.9 million were recognized in other comprehensive income. Derivative settlements during the year totaled $13.0 million. The fair values of our natural gas and crude oil price collars and swaps are valued based upon quotes obtained from counterparties to the agreements and are designated as Level 3. Such quotes have been derived using a Black-Scholes model for the active oil and gas commodities market that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term. Although we utilize multiple quotes to assess the reasonableness of our values, we have not attempted to obtain sufficient corroborating market evidence to support classifying these derivative contracts as Level 2. We adjust the fair value quotes received by our counterparties to take into account either the counterparties’ nonperformance risk or our own nonperformance risk. We measured the nonperformance risk of our counterparties by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions and made a reduction to our derivative receivable. In times where we have net derivative contract liabilities, our nonperformance risk is evaluated using a market credit spread provided by our bank. Additional disclosures are required for transactions measured at fair value and we have included these disclosures in Note 7 of the Notes to the Consolidated Financial Statements.

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 of return published for a theoretical portfolio of high-quality fixed income securities. In order to select the discount rate, we use benchmarks such as the Moody's Aa Corporate Rate, which was 5.54% as of December 31, 2008, and the Citigroup Pension Liability Index, which was 5.87% as of December 31, 2008. We look to these benchmarks as well as considering durations of expected benefit payments. We have determined based on these assumptions that a discount rate of 5.75% at December 31, 2008 is reasonable.

In order to value our pension liabilities, we use the RP-2000 Combined Mortality Table based on the demographics of our benefit plans. We have also assumed that salaries will increase four percent based on our expectation of future salary increases.

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, 2008, the assumed rate of increase was 9.0%. 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.

We have established objectives regarding plan assets in the pension plan. We attempt to maximize return over the long-term, subject to appropriate levels of risk. One of our plan objectives is that the performance of the equity portion of the pension plan exceed the Standard and Poors' 500 Index over the long-term. We also seek to achieve a minimum five percent annual real rate of return (above the rate of inflation) on the total portfolio over the long-term. We establish 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. In our pension calculations, we have used eight percent as the expected long-term return on plan assets for 2008, 2007 and 2006. A Monte Carlo simulation was run using 5,000 simulations based upon our actual asset allocation and liability duration, which has been determined to be approximately 15 years. This model uses historical data for the period of 1926-2007 for stocks, bonds and cash to determine the best estimate range of future returns. The median rate of return, or return that we expect to achieve over 50 percent of the time, is approximately nine percent. We expect to achieve at a minimum approximately 7% annual real rate of return on the total portfolio over the long-term at least 75 percent of the time. We believe that the eight percent chosen is a reasonable estimate based on our actual results.

We generally target a portfolio of assets utilizing equity securities, fixed income securities and cash equivalents that are within a range of approximately 50% to 80% for equity securities and approximately 20% to 40% for fixed income securities. Large capitalization equities may make up a maximum of 65% of the portfolio. Small capitalization equities and international equities may make up a maximum of 30% and 15%, respectively, of the portfolio. Fixed income bonds may make up a maximum of 40% of our portfolio. The account will typically be fully invested; however, as a temporary investment or an asset protection measure, part of the account may be invested in money market investments up to 20%. One percent of the portfolio is invested in short-term funds at the designated bank to meet the cash flow needs of the plan. No prohibited investments, including direct or indirect investments in commodities, commodity futures, derivatives, short sales, real estate investment trusts, letter stock, restricted stock or other private placements, are allowed without prior committee approval.

Stock-Based Compensation

We account for stock-based compensation under a fair value based method of accounting for stock options and similar equity instruments. 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. To calculate the fair value, either a binomial or Black-Scholes valuation model may be used. Stock-based compensation cost for all types of awards is included in General and Administrative Expense in the Consolidated Statement of Operations.

Stock options and stock appreciation rights (SARs) are granted with an exercise price equal to the average of the high and low trading price of our stock on the grant date. The grant date fair value is calculated by using a Black-Scholes model that incorporations assumptions for stock price volatility, risk free rate of return, expected dividend and expected term. The expected term was derived by reviewing minimum and maximum expected term outputs from the Black-Scholes model based on award type and employee type. This term represents the period of time that awards granted are expected to be outstanding. The stock price volatility was calculated using our historical closing stock price data for the period associated with the expected term through the grant date of each award. The risk free rate of return percentages are based on the continuously compounded equivalent of the US Treasury (Nominal 10) within the expected term as measured on the grant date. The expected dividend percentage assumes that we will continue to pay a consistent level of dividend each quarter. Expense is recorded based on a graded-vesting schedule over a three year service period, with one-third of the award becoming exercisable each year on the anniversary date of the grant. The forfeiture rate is determined based on the forfeiture history by type of award and by the group of individuals receiving the award.

The fair value of restricted stock awards, restricted stock units and certain performance share awards (which contain vesting restrictions based either on operating income or internal performance metrics) are measured based on the average of the high and low trading price of our stock on the grant date. Restricted stock awards primarily vest either at the end of a three year service period, or on a graded-vesting basis of one-third at each anniversary date over a three year service period. The annual forfeiture rate for restricted stock awards ranges from 0% to 7.2% based on approximately ten years of our history for this type of award to various employee groups. Performance shares that vest based on operating income vest on a graded-vesting basis of one-third at each anniversary date over a three year service period and no forfeiture rate is assumed. Performance shares that vest based on internal metrics vest at the end of a three year performance period and an annual forfeiture rate of 4.5% is assumed. Expense for restricted stock units is recorded immediately as these awards vest immediately. Restricted stock units are granted only to our directors and no forfeiture rate is assumed.

We grant another type of performance share award to executive employees that vest at the end of a three year performance period based on the comparative performance of our stock measured against sixteen other companies in our peer group. Depending on our performance, up to 100% of the fair market value of a share of our stock may be payable in stock plus an additional 100% of the fair market value of a share of our stock may be payable in cash. These awards are accounted for by bifurcating the equity and liability components. A Monte

Carlo model is used to value the liability component as well as the equity portion of the certain awards on the date of grant. The four primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns, correlation in movement of total shareholder return and the expected dividend. The risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for one and two year bonds and is set equal to the yield, for the period over the remaining duration of the performance period, on treasury securities as of the reporting date. Volatility was set equal to the annualized daily volatility measured over a historic one and two year period ending on the reporting date. Correlation in movement of total shareholder return was determined based on a correlation matrix that was created which identifies total shareholder return correlations for each pair of companies in the peer group, including us. The paired returns in the correlation matrix ranged from approximately 71% to approximately 89% for us and our peer group. The expected dividend is calculated using our dividends paid ($0.12 for 2008) divided by the December 31, 2008 closing price of our stock ($26.00). Based on these inputs discussed above, a ranking was projected identifying our rank relative to the peer group. No forfeiture rate is assumed for this type of award. Expense related to these awards can be volatile based on our comparative ranking at the end of each quarter.

We used the shortcut approach to derive our initial windfall tax benefit pool. We chose to use a one-pool approach which combines all awards granted to employees, including non-employee directors.

On January 16, 2008, our Board of Directors adopted a Supplemental Employee Incentive Plan. The plan was intended to provide a compensation tool tied to stock market value creation to serve as an incentive and retention vehicle for full-time non-officer employees by providing for cash payments in the event our common stock reached specified trading prices. The bonus payout of a minimum of 50% of an employee's base salary was triggered if, for any 20 trading days (which need not be consecutive) that fell within a period of 60 consecutive trading days occurring on or before November 1, 2011, the closing price per share of our common stock equaled or exceeded the final price goal of $60 per share. The plan also provided that an interim distribution of 10% of an employee's base salary would be paid to eligible employees upon achieving the interim price goal of $50 per share prior to December 31, 2009.

On the January 16, 2008 adoption date of the plan, our closing stock price was $40.71. On April 8, 2008 and subsequently on June 2, 2008, we achieved the interim and final target goals and total distributions of $15.7 million were paid in 2009. No further distributions will be made under this plan.

On July 24, 2008, our Board of Directors adopted a second Supplemental Employee Incentive Plan ("Plan II"). Plan II is similar to the January 2008 Supplemental Incentive Plan; however, the final target is that the closing price per share of our common stock must equal or exceed the price goal of $105 per share on or before June 20, 2012. Under Plan II, each eligible employee may receive (upon approval by the Compensation Committee) a distribution of 50% of his or her base salary (or 30% of base salary if we paid interim distributions upon the achievement of the interim price goal discussed below). Plan II provides that a distribution of 20% of an eligible employee's base salary upon achieving the interim price goal of $85 per share on or before June 30, 2010. The Compensation Committee can increase the 50% or 20% payment as it applies to any employee. Payments under this plan will partially be paid within 15 business days after achieving the target and the remaining portion will be paid based on a separate payment date as described in Plan II.

These awards under both plans discussed above have been accounted for as liability awards under SFAS No. 123(R), and the total expense for 2008 was $15.9 million. For further information regarding the supplemental employee incentive plans and our other stock-based compensation awards, please refer to Note 10 of the Notes to the Consolidated Financial Statements.

OTHER ISSUES AND CONTINGENCIES

Regulations. Our operations are subject to various types of regulation by federal, state and local authorities. See "Regulation of Oil and Natural Gas Exploration and Production," "Natural Gas Marketing, Gathering and

Transportation," "Federal Regulation of Petroleum" and "Environmental Regulations" in the "Other Business Matters" section of Item 1 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 our various debt instruments. Among other requirements, our revolving credit agreement and our senior 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. Our senior notes require us to maintain a ratio of cash and proved reserves to indebtedness and other liabilities of 1.5 to 1.0. At December 31, 2008, we were in compliance in all material respects with all restrictive covenants on both the revolving credit agreement and notes. In the unforeseen event that we fail to comply with these covenants, we 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."

Operating Risks and Insurance Coverage. Our business involves a variety of operating risks. See "Risk Factors—We face a variety of hazards and risks that could cause substantial financial losses" in Item 1A. 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 have a material adverse effect on 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 trigger an impairment under SFAS No. 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 derivative financial instruments. Most recently, we have used financial instruments such as price collars and swap arrangements to reduce the impact of declining prices on our revenue. Under both arrangements, there is also a risk that the movement of index prices may result in our inability to realize the full benefit of an improvement in market conditions.

Recently Issued Accounting Pronouncements

In December 2008, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting," which amends the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, as well as adding a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which is being phased out. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 will be required to price proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning January 1, 2010. We are currently evaluating what impact Release No. 33-8995 may have on our financial position, results of operations or cash flows.

In June 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. Emerging Issues Task Force (EITF) 03-6-1, “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.” Under this FSP, unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents, whether they are paid or unpaid, are considered participating securities and should be included in the computation of earnings per share pursuant to the two-class method. FSP No. EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. In addition, all prior period earnings per share data presented should be adjusted retrospectively and early application is not permitted. We do not believe that FSP No. EITF 03-6-1 will have a material impact on our financial position, results of operations or cash flows.

In May 2008, the FASB issued SFAS No. 162, “The Hierarchy of Generally Accepted Accounting Principles,” which identifies a consistent framework for selecting accounting principles to be used in preparing financial statements for nongovernmental entities that are presented in conformity with United States generally accepted accounting principles (GAAP). The current GAAP hierarchy was criticized due to its complexity, ranking position of FASB Statements of Financial Accounting Concepts and the fact that it is directed at auditors rather than entities. SFAS No. 162 will be effective 60 days following the SEC’s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, “The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles.” The FASB does not expect that SFAS No. 162 will have a change in current practice, and we do not believe that SFAS No. 162 will have an impact on our financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities,” which amends SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities.” Enhanced disclosures to improve financial reporting transparency are required and include disclosure about the location and amounts of derivative instruments in the financial statements, how derivative instruments are accounted for and how derivatives affect an entity’s financial position, financial performance and cash flows. A tabular format including the fair value of derivative instruments and their gains and losses, disclosure about credit risk-related derivative features and cross-referencing within the footnotes are also new requirements. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application and comparative disclosures encouraged, but not required. We have not yet adopted SFAS No. 161. We do not believe that there will be an impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), “Business Combinations.” SFAS No. 141(R) was issued in an effort to continue the movement toward the greater use of fair values in financial reporting and increased transparency through expanded disclosures. It changes how business acquisitions are accounted for and will impact financial statements at the acquisition date and in subsequent periods. Certain of these changes will introduce more volatility into earnings. The acquirer must now record all assets and liabilities of the acquired business at fair value, and related transaction and restructuring costs will be expensed rather than the previous method of being capitalized as part of the acquisition. SFAS No. 141(R) also impacts the annual goodwill impairment test associated with acquisitions, including those that close before the effective date of SFAS No. 141(R). The definitions of a “business” and a “business combination” have been expanded, resulting in more transactions qualifying as business combinations. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 31, 2008 and earlier adoption is prohibited. We cannot predict the impact that the adoption of SFAS No. 141(R) will have on our financial position, results of operations or cash flows with respect to any acquisitions completed after December 31, 2008.

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. See "Risk Factors" in Item 1A for additional information about these risks and uncertainties. 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

2008 and 2007 Compared

We reported net income for the year ended December 31, 2008 of $211.3 million, or $2.10 per share. During 2007, we reported net income of $167.4 million, or $1.73 per share. This increase of $43.9 million in net income was primarily due to an increase in operating revenues and gains on asset sales and settlements, partially offset by increased operating, interest and income tax expenses. Operating revenues increased by $213.6 million, largely due to increases in both natural gas production revenues and brokered natural gas revenues and crude oil and condensate revenues. Operating expenses increased by $155.9 million between periods due to increases in all categories of operating expenses other than exploration expense. In addition, net income was impacted by an increase in gain on sale of assets and gain on settlement of dispute of $39.6 million as well as an increase in expenses of $53.4 million resulting from a combination of increased income tax expense and interest and other expenses. Income tax expense was higher in 2008 as a result of higher income before income taxes in 2008 compared to 2007, in addition to an increase in the effective tax rate.

Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $8.39 per Mcf for 2008 compared to $7.23 per Mcf for 2007. These prices include the realized impact of derivative instrument settlements, which increased the price by $0.20 per Mcf in 2008 and by $0.99 per Mcf in 2007. There was no revenue impact from the unrealized change in natural gas derivative fair value for the years ended December 31, 2008 and 2007.

	Year Ended December 31,		Variance	
	2008	**2007**	**Amount**	**Percent**
Natural Gas Production *(Mmcf)*				
East	**25,171**	24,344	827	3%
Gulf Coast	**34,577**	26,797	7,780	29%
West	**26,535**	25,409	1,126	4%
Canada	**4,142**	3,925	217	6%
Total Company	**90,425**	80,475	9,950	12%
Natural Gas Production Sales Price *($/Mcf)*				
East	**$ 8.54**	$ 7.78	$ 0.76	10%
Gulf Coast	**$ 9.23**	$ 8.03	$ 1.20	15%
West	**$ 7.28**	$ 6.13	$ 1.15	19%
Canada	**$ 7.62**	$ 5.47	$ 2.15	39%
Total Company	**$ 8.39**	$ 7.23	$ 1.16	16%
Natural Gas Production Revenue *(In thousands)*				
East	**$214,852**	$189,392	$ 25,460	13%
Gulf Coast	**319,246**	215,106	104,140	48%
West	**193,100**	155,676	37,424	24%
Canada	**31,557**	21,466	10,091	47%
Total Company	**$758,755**	$581,640	$177,115	30%

	Year Ended December 31, 2008	2007	Variance Amount	Percent
Price Variance Impact on Natural Gas Production Revenue				
(In thousands)				
East	**$19,029**			
Gulf Coast	**41,347**			
West	**30,524**			
Canada	**8,906**			
Total Company	**$99,806**			
Volume Variance Impact on Natural Gas Production Revenue				
(In thousands)				
East	**$ 6,431**			
Gulf Coast	**62,793**			
West	**6,900**			
Canada	**1,185**			
Total Company	**$77,309**			

The increase in Natural Gas Production Revenue of $177.1 million is due to the increase in realized natural gas sales prices in addition to an increase in natural gas production. Natural gas production in the Gulf Coast region increased due to increased production in the Minden field, largely due to the properties we acquired in east Texas in August 2008, as well as increased drilling in the County Line field. In addition, natural gas production increased in the West region associated with an increase in the drilling program, increased in the East region as a result of increased drilling activity in West Virginia and northeastern Pennsylvania. Canada increased due to drilling in the Hinton field.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31, 2008	2007	Variance Amount	Percent
Sales Price *($/Mcf)*	**$ 10.39**	$ 8.40	$ 1.99	24%
Volume Brokered *(Mmcf)*	**x 10,996**	x11,101	(105)	(1%)
Brokered Natural Gas Revenues *(In thousands)*	**$114,220**	$93,215		
Purchase Price *($/Mcf)*	**$ 9.14**	$ 7.37	$ 1.77	24%
Volume Brokered *(Mmcf)*	**x 10,996**	x11,101	(105)	(1%)
Brokered Natural Gas Cost *(In thousands)*	**$100,449**	$81,819		
Brokered Natural Gas Margin *(In thousands)*	**$ 13,771**	$11,396	$2,375	21%
(In thousands)				
Sales Price Variance Impact on Revenue	**$ 21,882**			
Volume Variance Impact on Revenue	**(882)**			
	$ 21,000			
(In thousands)				
Purchase Price Variance Impact on Purchases	**$ (19,399)**			
Volume Variance Impact on Purchases	**774**			
	$ (18,625)			

The increased brokered natural gas margin of $2.4 million is a result of an increase in sales price that outpaced the increase in purchase price, partially offset by a decrease in the volumes brokered in 2008 over 2007.

Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price was $89.11 per Bbl for 2008 compared to $67.16 per Bbl for 2007. These prices include the realized impact of derivative instrument settlements, which decreased the price by $6.33 per Bbl in 2008 and by $0.97 per Bbl in 2007. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value in 2008 or 2007.

	Year Ended December 31,		Variance	
	2008	**2007**	**Amount**	**Percent**
Crude Oil Production *(Mbbl)*				
East	**23**	26	(3)	(12%)
Gulf Coast	**578**	605	(27)	(4%)
West	**160**	174	(14)	(8%)
Canada	**21**	18	3	17%
Total Company	**782**	823	(41)	(5%)
Crude Oil Sales Price *($/Bbl)*				
East	**$ 92.07**	$ 66.97	$ 25.10	37%
Gulf Coast	**$ 87.39**	$ 67.17	$ 20.22	30%
West	**$ 95.48**	$ 67.86	$ 27.62	41%
Canada	**$ 85.08**	$ 59.96	$ 25.12	42%
Total Company	**$ 89.11**	$ 67.16	$ 21.95	33%
Crude Oil Revenue *(In thousands)*				
East	**$ 2,101**	$ 1,734	$ 367	21%
Gulf Coast	**50,540**	40,673	9,867	24%
West	**15,243**	11,784	3,459	29%
Canada	**1,827**	1,052	775	74%
Total Company	**$69,711**	$55,243	$14,468	26%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ 573**			
Gulf Coast	**11,691**			
West	**4,409**			
Canada	**600**			
Total Company	**$17,273**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ (206)**			
Gulf Coast	**(1,824)**			
West	**(950)**			
Canada	**175**			
Total Company	**$ (2,805)**			

The increase in realized crude oil prices, partially offset by a decrease in production, resulted in a net revenue increase of $14.4 million. The decrease in oil production is mainly the result of a natural decline in crude oil production in the Gulf Coast and West regions.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized impact of cash settlements and the net unrealized change in fair value of derivative instruments:

	Year Ended December 31,			
	2008		2007	
	Realized	Unrealized	Realized	Unrealized
	(In thousands)			
Operating Revenues - Increase/(Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$17,972**	**$—**	$79,838	$—
Crude Oil	**(4,951)**	**—**	(796)	—
Total Cash Flow Hedges	**$13,021**	**$—**	$79,042	$—

We are exposed to market risk on derivative instruments to the extent of changes in market prices of natural gas and oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. 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. We do not anticipate any material impact on our financial results due to non-performance by third parties. Our primary derivative contract counterparties are JPMorgan Chase, Morgan Stanley, BNP Paribas, Goldman Sachs, and Bank of Montreal.

Operating Expenses

Total costs and expenses from operations increased by $155.9 million in 2008 from 2007. The primary reasons for this fluctuation are as follows:

- Depreciation, Depletion and Amortization increased by $41.5 million from 2007 to 2008. This is primarily due to the impact on the DD&A rate of higher capital costs and higher natural gas production volumes, including the east Texas acquisition.
- Impairment of Oil & Gas Properties and Other Assets increased by $31.1 million from 2007 to 2008 primarily related to impairments of approximately $28.3 million in the Trawick field in Rusk County, Texas in the Gulf Coast region resulting from a decline in natural gas prices and higher well costs as well as $3.0 million in the Corral Creek field in Washakie County, Wyoming in the West region resulting from lower than expected performance from the two well field.
- General and Administrative expenses increased by $23.4 million from 2007 to 2008. This is primarily due to increased stock compensation expense related to the payouts of our supplemental employee incentive plan bonuses ($15.7 million) as well as increased expense related to our performance share awards ($5.1 million).
- Impairment of Unproved Properties increased by $22.5 million from 2007 to 2008, primarily due to increased lease acquisition costs in several exploratory and developmental areas, as well as a $17.0 million charge for the impairment of three exploratory oil and gas prospects located in Mississippi, Montana and North Dakota. These prospects were impaired as a result of the significant decline in commodity prices in the fourth quarter of 2008 and abandonment of our exploration plans.
- Brokered Natural Gas Cost increased by $18.6 million from 2007 to 2008. See the preceding table titled "Brokered Natural Gas Revenue and Cost" for further analysis.
- Direct Operations expenses increased by $14.6 million from 2007 to 2008 primarily due to higher personnel and labor expenses, maintenance expenses, treating, compressor, pipeline and workover costs and vehicle and fuel expenses, partially offset by lower insurance costs.

- Taxes Other Than Income increased by $12.8 million from 2007 to 2008 due to higher production taxes as a result of higher operating revenues and, to a lesser extent, higher ad valorem taxes, partially offset by lower franchise taxes.
- Exploration expense decreased by $8.6 million from 2007 to 2008 primarily due to fewer dry holes, partially offset by increased geological and geophysical costs.

Interest Expense, Net

Interest expense, net increased by $19.2 million in 2008 compared to 2007 primarily due to increased interest expense related to the debt we issued in our July and December 2008 private placements and, to a lesser extent, higher average credit facility borrowings, offset in part by a lower weighted-average interest rate on our revolving credit facility borrowings and lower outstanding borrowings on our 7.19% fixed rate debt. Weighted-average borrowings under our credit facility based on daily balances were approximately $172 million during 2008 compared to approximately $52 million during 2007. The weighted-average effective interest rate on the credit facility decreased to 4.8% during 2008 from 7.2% during 2007.

Income Tax Expense

Income tax expense increased by $34.2 million due to a comparable increase in our pre-tax income. The effective tax rates for 2008 and 2007 were 37.0% and 35.0%, respectively. The increase in the effective tax rate is primarily due to a one time benefit for state taxes in 2007 of approximately $2.8 million attributable to favorable treatment of the gain from the sale of south Louisiana properties in 2006 and a reduction in special deductions in 2008.

2007 and 2006 Compared

We reported net income for the year ended December 31, 2007 of $167.4 million, or $1.73 per share. During 2006, we reported net income of $321.2 million, or $3.32 per share. This decrease of $153.8 million in net income was primarily due to a decrease in operating income of $254.2 million resulting from the gain on sale of assets of $231.2 million included in 2006 related to the 2006 south Louisiana and offshore properties sale, partially offset by a $99.2 million decrease in income tax expense and a $1.2 million decrease in interest and other expenses in 2007.

The decrease in operating income was primarily the result of a decrease in 2007 of $218.6 million in gain on sale of assets primarily from the 2006 south Louisiana and offshore properties sale. Additionally, there was a $29.8 million decrease in 2007 in operating revenues and an increase of $5.8 million in operating expenses. The decrease in operating revenues was largely the result of lower oil production in the Gulf Coast region primarily as a result of the 2006 south Louisiana and offshore properties sale. The increase in operating expenses was primarily the result of increased DD&A and impairment expenses, offset in part by reduced exploration and general and administrative expenses.

Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $7.23 per Mcf for 2007 compared to $7.13 per Mcf for 2006. These prices include the realized impact of derivative instrument settlements, which increased the price by $0.99 per Mcf in 2007 and $0.35 per Mcf in 2006. There was no revenue impact from the unrealized change in natural gas derivative fair value for the years ended December 31, 2007 or 2006.

	Year Ended December 31,		Variance	
	2007	**2006**	**Amount**	**Percent**
Natural Gas Production *(Mmcf)*				
East	24,344	23,542	802	3%
Gulf Coast	26,797	29,973	(3,176)	(11%)
West	25,409	23,633	1,776	8%
Canada	3,925	2,574	1,351	52%
Total Company	80,475	79,722	753	1%
Natural Gas Production Sales Price *($/Mcf)*				
East	$ 7.78	$ 7.99	$ (0.21)	(3%)
Gulf Coast	$ 8.03	$ 7.37	$ 0.66	9%
West	$ 6.13	$ 6.05	$ 0.08	1%
Canada	$ 5.47	$ 6.18	$ (0.71)	(11%)
Total Company	$ 7.23	$ 7.13	$ 0.10	1%
Natural Gas Production Revenue *(In thousands)*				
East	$189,392	$188,111	$ 1,281	1%
Gulf Coast	215,106	221,020	(5,914)	(3%)
West	155,676	143,058	12,618	9%
Canada	21,466	15,908	5,558	35%
Total Company	$581,640	$568,097	$13,543	2%
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	$ (5,127)			
Gulf Coast	17,774			
West	2,121			
Canada	(2,792)			
Total Company	$ 11,976			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	$ 6,408			
Gulf Coast	(23,688)			
West	10,497			
Canada	8,350			
Total Company	$ 1,567			

The increase of $13.5 million in Natural Gas Production Revenue is due to an increase in realized natural gas sales prices as well as increased natural gas production. Natural gas revenues increased in all regions except for the Gulf Coast region in 2007 over 2006. After removing from the 2006 results $70.5 million of natural gas revenues and 9,037 Mmcf of natural gas production associated with properties in the Gulf Coast region sold in the 2006 south Louisiana and offshore properties sale, total natural gas revenue would have increased by $84.0 million, or 17%, and natural gas production would have increased by 9,791 Mmcf, or 14%, from 2006 to 2007.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31,		Variance	
	2007	**2006**	**Amount**	**Percent**
Sales Price *($/Mcf)*	$ 8.40	$ 8.14	$ 0.26	3%
Volume Brokered *(Mmcf)*	x11,101	x11,502	(401)	(3%)
Brokered Natural Gas Revenues *(In thousands)*	$93,215	$93,651		
Purchase Price *($/Mcf)*	$ 7.37	$ 7.25	$ 0.12	2%
Volume Brokered *(Mmcf)*	x11,101	x11,502	(401)	(3%)
Brokered Natural Gas Cost *(In thousands)*	$81,819	$83,375		
Brokered Natural Gas Margin *(In thousands)*	$11,396	$10,276	$1,120	11%

(In thousands)	
Sales Price Variance Impact on Revenue	$ 2,828
Volume Variance Impact on Revenue	(3,264)
	$ (436)

(In thousands)	
Purchase Price Variance Impact on Purchases	$ (1,351)
Volume Variance Impact on Purchases	2,907
	$ 1,556

The increased brokered natural gas margin of approximately $1.1 million is driven by an increase in sales price that outpaced the increase in purchase price, partially offset by a decrease in the volumes brokered in 2007 over 2006.

Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price was $67.16 per Bbl for 2007. The 2007 price includes the realized impact of derivative instrument settlements which decreased the price by $0.97 per Bbl. Our average total company realized crude oil sales price was $65.03 per Bbl for 2006. There was no realized impact of crude oil derivative instruments in 2006. There was no unrealized impact of crude oil derivative instruments in 2007 or 2006.

	Year Ended December 31,		Variance	
	2007	2006	Amount	Percent
Crude Oil Production *(Mbbl)*				
East	26	24	2	8%
Gulf Coast	605	1,160	(555)	(48%)
West	174	209	(35)	(17%)
Canada	18	12	6	50%
Total Company	823	1,405	(582)	(41%)
Crude Oil Sales Price *($/Bbl)*				
East	$ 66.97	$ 62.03	$ 4.94	8%
Gulf Coast	$ 67.17	$ 65.44	$ 1.73	3%
West	$ 67.86	$ 63.36	$ 4.50	7%
Canada	$ 59.96	$ 60.55	$ (0.59)	(1%)
Total Company	$ 67.16	$ 65.03	$ 2.13	3%
Crude Oil Revenue *(In thousands)*				
East	$ 1,734	$ 1,474	$ 260	18%
Gulf Coast	40,673	75,894	(35,221)	(46%)
West	11,784	13,253	(1,469)	(11%)
Canada	1,052	759	293	39%
Total Company	$ 55,243	$91,380	$(36,137)	(40%)
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
East	$ 128			
Gulf Coast	1,048			
West	781			
Canada	(10)			
Total Company	$ 1,947			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
East	$ 132			
Gulf Coast	(36,269)			
West	(2,250)			
Canada	303			
Total Company	$(38,084)			

The decrease in the realized crude oil production, partially offset by the increase in realized prices, resulted in a net revenue decrease of approximately $36.1 million. The decrease in oil production is mainly the result of the 2006 south Louisiana and offshore properties sale in the Gulf Coast region. After removing from the 2006 results $47.4 million of crude oil revenues and 707 Mbbls of crude oil production associated with properties in the Gulf Coast region sold in the 2006 south Louisiana and offshore properties sale, total crude oil revenue would have increased by $11.2 million, or 26%, and crude oil production would have increased by 124 Mbbls, or 18%, from 2006 to 2007.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized impact of cash settlements and the net unrealized change in fair value of derivative instruments:

	Year Ended December 31,			
	2007		2006	
	Realized	Unrealized	Realized	Unrealized
	(In thousands)			
Operating Revenues—Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	$79,838	$—	$28,266	$—
Crude Oil	(796)	—	—	—
Total Cash Flow Hedges	$79,042	$—	$28,266	$—

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

Operating Expenses

Total costs and expenses from operations increased by $5.8 million for the year ended December 31, 2007 compared to the year ended December 31, 2006. The primary reasons for this fluctuation are as follows:

- Depreciation, Depletion and Amortization increased by $14.9 million in 2007 over 2006. This is primarily due to the impact on the DD&A rate of negative reserve revisions due to lower prices at the end of 2006, higher capital costs and commencement of production in an east Texas field.
- Exploration expense decreased by $9.6 million from 2006 to 2007, primarily as a result of a decrease in total dry hole expense of $10.3 million, primarily in Canada and, to a lesser extent, in the West and Gulf Coast regions. In addition, there was a decrease in geophysical and geological expenses of $1.8 million, primarily due to a decrease in the Gulf Coast region, offset in part by an increase in Canada. Offsetting part of these decreases was an increase of $2.6 million in land and lease search expenses during 2007.
- Impairment of Unproved Properties increased by $7.9 million in 2007 compared to 2006, primarily due to increased lease acquisition costs during 2005 and 2006 in several exploratory areas.
- General and Administrative expense decreased by $7.4 million in 2007 primarily due to decreased stock compensation charges of $5.9 million due to a reduction in performance share expense from a change in the liability component of the awards resulting from the variance in our relative ranking from 2006 to 2007 as well as a reduction in restricted stock awards as a result of awards that vested in 2007. In addition, there was a decrease of $4.2 million related to decreased professional services fees for litigation. Partially offsetting these decreases were increases in employee compensation related expenses and bad debt expense.
- Direct Operations expense increased by $2.4 million as a result of higher employee compensation charges and disposal, treating, compressor, workover and maintenance costs, partially offset by lower outside operated properties expense and insurance expense.
- Brokered Natural Gas Cost decreased by $1.6 million from 2006 to 2007. See the preceding table labeled “Brokered Natural Gas Revenue and Cost” for further analysis.
- Taxes Other Than Income decreased by $1.5 million for 2007 compared to 2006, primarily due to decreased production taxes of $3.3 million as a result of decreased commodity volumes and prices as well as decreased franchise taxes, partially offset by an increase in ad valorem taxes.

- Impairment of Oil & Gas Properties and Other Assets increased by $0.7 million for the year ended December 31, 2007 compared to the year ended December 31, 2006, due to an impairment recorded in 2007 in the Gulf Coast region resulting from two non-commercial development completions in a small field in north Louisiana.

Interest Expense, Net

Interest expense, net decreased by $1.1 million in 2007 compared to 2006 due to a lower weighted-average interest rate on borrowings under our revolving credit facility, a lower outstanding principal amount of our 7.19% fixed rate debt and lower weighted-average borrowings under our credit facility, as well as increased income related to FIN 48 as discussed below. These decreases to interest expense were offset in part by decreased regulatory capitalized interest on our pipeline in the East region. Weighted-average borrowings under our credit facility based on daily balances were approximately $52 million during 2007 compared to approximately $61 million during 2006. The weighted-average effective interest rate on the credit facility decreased to 7.2% during 2007 from 7.9% during 2006. In addition, interest expense decreased due to the reversal of interest payable on a previous uncertain tax position. During 2007, we recorded net interest income related to FIN 48 of $1.3 million, with no amount recorded in 2006.

Income Tax Expense

Income tax expense decreased by $99.2 million due to a comparable decrease in our pre-tax income, primarily as a result of the decrease in the gain on sale of assets. The effective tax rates for 2007 and 2006 were 35.0% and 37.1%, respectively. The decrease in the effective tax rate is primarily due to a reduction in our overall state income tax rate for 2007.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk

Our primary market risk is exposure to oil and natural gas prices. Realized prices are mainly driven by worldwide prices for oil and spot market prices for North American natural gas production. Commodity prices are volatile and unpredictable.

The debt and equity markets have recently experienced unfavorable conditions, which may affect our ability to access those markets. As a result of the volatility and disruption in the capital markets and our increased level of borrowings, we may experience increased costs associated with future borrowings and debt issuances. At this time, we do not believe our liquidity has been materially affected by the recent market events. We will continue to monitor events and circumstances surrounding each of our lenders in our revolving credit facility.

Derivative Instruments and Hedging Activity

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 limit the benefit to us of increases in prices, but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges. Please read the discussion below as well as Note 11 of the Notes to the Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

Periodically, we enter into derivative commodity instruments to hedge our exposure to price fluctuations on natural gas and crude oil production. Our credit agreement restricts our ability to enter into commodity hedges other than to hedge or mitigate risks to which we have actual or projected exposure or as permitted under our risk management policies and not subjecting us to material speculative risks. At December 31, 2008, we had 26 cash flow hedges open: 14 natural gas price collar arrangements, 10 natural gas price swap arrangements and two crude oil price swap arrangements. At December 31, 2008, a $355.2 million ($223.1 million, net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income / (Loss), along with a $264.7 million short-term derivative receivable and a $90.5 million long-term derivative receivable.

The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Accumulated Other Comprehensive Income / (Loss). The ineffective portion of the change in the fair value of derivatives designated as hedges, and the change in fair value of all other derivatives, are recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate Revenue, as appropriate. For the years ended December 31 2008, 2007 and 2006, there was no ineffectiveness recorded in the Consolidated Statement of Operations.

During the second quarter of 2008, in anticipation of the east Texas acquisition, we entered into 12 contracts for natural gas price swaps and three contracts for crude oil swaps (2009 and 2010 contracts included in the amounts discussed above) for the remainder of 2008 and extending through 2010 for the purpose of reducing commodity price risk associated with anticipated production after the transaction closing.

Based upon estimates at December 31, 2008, we would expect to reclassify to the Consolidated Statement of Operations, over the next 12 months, $166.2 million in after-tax income associated with commodity hedges. This reclassification represents the net short-term receivable associated with open positions currently not reflected in earnings at December 31, 2008 related to anticipated 2009 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 cash flow hedges are not held for trading purposes. Under these price swaps, we receive a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures.

During 2008, natural gas price swaps covered 9,821 Mmcf, or 11%, of our 2008 gas production at an average price of $10.27 per Mcf. During 2008, we entered into natural gas price swaps covering a portion of our anticipated 2008, 2009 and 2010 production, including production related to the east Texas acquisition.

At December 31, 2008, we had open natural gas price swap contracts covering a portion of our anticipated 2009 and 2010 production as follows:

	Natural Gas Price Swaps		
Contract Period	**Volume in Mmcf**	**Weighted-Average Contract Price (per Mcf)**	**Net Unrealized Gain (In thousands)**
Year Ended December 31, 2009	16,079	$12.18	$90,267
Year Ended December 31, 2010	19,295	$11.43	$70,345

We had one crude oil price swap covering 92 Mbbl, or 12%, of our 2008 production at a price of $127.15 per Bbl. During 2008, we entered into crude oil price swaps covering a portion of our anticipated 2008, 2009 and 2010 production.

At December 31, 2008, we had open crude oil price swap contracts covering a portion of our anticipated 2009 and 2010 production as follows:

Contract Period	Crude Oil Price Swaps		
	Volume in Mbbl	Contract Price (per Bbl)	Net Unrealized Gain (In thousands)
Year Ended December 31, 2009	365	$125.25	$25,656
Year Ended December 31, 2010	365	$125.00	$21,840

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 price falls below the floor price, the counterparty pays us. During 2008, natural gas price collars covered 54,173 Mmcf, or 60%, of our 2008 gas production, with a weighted-average floor of $8.53 per Mcf and a weighted-average ceiling of $10.70 per Mcf.

At December 31, 2008, we had open natural gas price collar contracts covering a portion of our anticipated 2009 production as follows:

Contract Period	Natural Gas Price Collars		
	Volume in Mmcf	Weighted-Average Ceiling / Floor (per Mcf)	Net Unrealized Gain (In thousands)
Year Ended December 31, 2009	47,253	$12.39/$9.40	$152,191

During 2008, an oil price collar covered 366 Mbbls, or 47%, of our 2008 crude oil production, with a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl.

We are exposed to market risk on these open contracts, to the extent of changes in market prices of natural gas and crude 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 amounts set forth under the net unrealized gain columns in the tables above represent our total unrealized gain position at December 31, 2008. Also impacting the total unrealized net gain (reflecting the net receivable position) in accumulated other comprehensive income / (loss) in the Consolidated Balance Sheet is a reduction of $5.1 million related to our assessment of our counterparties' nonperformance risk. This risk was evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions.

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" for further details.

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 fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the year- end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our fixed-rate notes to new issues (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the fixed-rate notes, excluding the credit facility, are based on interest rates currently available to us. The credit facility approximates fair value because this instrument bears interest at rates based on current market rates.

We use available marketing data and valuation methodologies to estimate the fair value of debt.

Long-Term Debt

	December 31, 2008		December 31, 2007	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(In thousands)			
Long-Term Debt	**$867,000**	**$807,508**	$350,000	$364,500
Current Maturities	**(35,857)**	**(35,796)**	(20,000)	(20,466)
Long-Term Debt, excluding Current Maturities	**$831,143**	**$771,712**	$330,000	$344,034

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Cabot Oil & Gas Corporation and its subsidiaries (the "Company") at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 11 to the consolidated financial statements, the Company changed the manner in which it accounts for and reports fair value measurements in 2008. As discussed in Note 5 to the consolidated financial statements, the Company changed the manner in which it accounts for its defined benefit pension and other postretirement plans in 2006.

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.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2009

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF OPERATIONS
(In thousands, except per share amounts)

	Year Ended December 31,		
	2008	**2007**	**2006**
OPERATING REVENUES			
Natural Gas Production	**$758,755**	$581,640	$568,097
Brokered Natural Gas	**114,220**	93,215	93,651
Crude Oil and Condensate	**69,711**	55,243	91,380
Other	**3,105**	2,072	8,860
	945,791	732,170	761,988
OPERATING EXPENSES			
Brokered Natural Gas Cost	**100,449**	81,819	83,375
Direct Operations—Field and Pipeline	**91,839**	77,170	74,790
Exploration	**31,200**	39,772	49,397
Depreciation, Depletion and Amortization	**185,403**	143,951	128,975
Impairment of Unproved Properties	**41,512**	19,042	11,117
Impairment of Oil & Gas Properties and Other Assets (Note 2)	**35,700**	4,614	3,886
General and Administrative	**74,185**	50,775	58,168
Taxes Other Than Income	**66,540**	53,782	55,351
	626,828	470,925	465,059
Gain on Sale of Assets	**1,143**	13,448	232,017
Gain on Settlement of Dispute (Note 7)	**51,906**	—	—
INCOME FROM OPERATIONS	**372,012**	274,693	528,946
Interest Expense and Other	**36,389**	17,161	18,441
Income Before Income Taxes	**335,623**	257,532	510,505
Income Tax Expense	**124,333**	90,109	189,330
NET INCOME	**$211,290**	$167,423	$321,175
Basic Earnings Per Share	**$ 2.10**	$ 1.73	$ 3.32
Diluted Earnings Per Share	**$ 2.08**	$ 1.71	$ 3.26
Weighted-Average Common Shares Outstanding	**100,737**	96,978	96,803
Diluted Common Shares (Note 13)	**101,726**	98,130	98,601

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

CABOT OIL & GAS CORPORATION

CONSOLIDATED BALANCE SHEET
(In thousands, except share amounts)

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 28,101**	$ 18,498
Accounts Receivable, Net (Note 3)	**109,087**	109,306
Income Taxes Receivable	**526**	3,832
Inventories (Note 3)	**45,677**	27,353
Deferred Income Taxes	**—**	22,526
Derivative Contracts (Note 11)	**264,660**	12,655
Other Current Assets (Note 3)	**12,500**	23,313
Total Current Assets	**460,551**	217,483
Properties and Equipment, Net (Successful Efforts Method) (Note 2)	**3,135,828**	1,908,117
Derivative Contracts (Note 11)	**90,542**	—
Other Assets (Note 3)	**14,743**	31,217
	$3,701,664	$2,156,817
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable (Note 3)	**$ 222,985**	$ 173,497
Current Portion of Long-Term Debt	**35,857**	20,000
Deferred Income Taxes	**63,985**	—
Income Taxes Payable	**5,535**	1,391
Derivative Contracts (Note 11)	**—**	5,383
Accrued Liabilities (Note 3)	**50,551**	48,065
Total Current Liabilities	**378,913**	248,336
Long-Term Liability for Pension and Postretirement Benefits (Note 5)	**54,714**	26,947
Long-Term Debt (Note 4)	**831,143**	330,000
Deferred Income Taxes	**599,106**	433,923
Other Liabilities (Note 3)	**47,226**	47,354
Commitments and Contingencies (Note 7)		
Stockholders' Equity		
Common Stock:		
Authorized—120,000,000 Shares of $0.10 Par Value		
Issued—103,561,268 Shares and 102,681,468 Shares in 2008 and 2007, respectively	**10,356**	10,268
Additional Paid-in Capital	**675,568**	424,229
Retained Earnings	**921,561**	722,344
Accumulated Other Comprehensive Income / (Loss) (Note 14)	**186,426**	(894)
Less Treasury Stock, at Cost: (Note 9)		
202,200 Shares and 5,204,700 Shares in 2008 and 2007, respectively	**(3,349)**	(85,690)
Total Stockholders' Equity	**1,790,562**	1,070,257
	$3,701,664	$2,156,817

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

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2008	**2007**	**2006**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 211,290**	$ 167,423	$ 321,175
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation, Depletion and Amortization	**185,403**	143,951	128,975
Impairment of Unproved Properties	**41,512**	19,042	11,117
Impairment of Oil & Gas Properties and Other Assets	**35,700**	4,614	3,886
Deferred Income Tax Expense	**120,851**	95,152	52,011
Gain on Sale of Assets	**(1,143)**	(13,448)	(232,017)
Gain on Settlement of Dispute	**(31,706)**	—	—
Exploration Expense	**31,200**	39,772	49,397
Stock-Based Compensation Expense and Other	**15,623**	16,241	21,271
Changes in Assets and Liabilities:			
Accounts Receivable, Net	**(3,928)**	6,854	39,463
Income Taxes Receivable	**34,521**	14,456	(11,198)
Inventories	**(18,324)**	5,644	(8,381)
Other Current Assets	**10,816**	(14,908)	1,007
Other Assets	**5,698**	(29,795)	(733)
Accounts Payable and Accrued Liabilities	**3,321**	1,052	(29,694)
Income Taxes Payable	**3,580**	(1,281)	18,398
Other Liabilities	**724**	7,368	1,912
Stock-Based Compensation Tax Benefit	**(10,691)**	—	(9,485)
Net Cash Provided by Operating Activities	**634,447**	462,137	357,104
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital Expenditures	**(817,440)**	(553,229)	(460,742)
Acquisitions	**(605,748)**	(3,982)	(6,688)
Proceeds from Sale of Assets	**2,099**	7,061	329,474
Exploration Expense	**(31,200)**	(39,772)	(49,397)
Net Cash Used in Investing Activities	**(1,452,289)**	(589,922)	(187,353)
CASH FLOWS FROM FINANCING ACTIVITIES			
Increase in Debt	**892,000**	175,000	205,000
Decrease in Debt	**(375,000)**	(65,000)	(305,000)
Net Proceeds from Sale of Common Stock	**316,230**	5,099	6,235
Stock-Based Compensation Tax Benefit	**10,691**	—	9,485
Purchase of Treasury Stock	**—**	—	(46,492)
Dividends Paid	**(12,073)**	(10,670)	(7,751)
Capitalized Debt Issuance Costs	**(4,403)**	—	—
Net Cash Provided by / (Used in) Financing Activities	**827,445**	104,429	(138,523)
Net Increase / (Decrease) in Cash and Cash Equivalents	**9,603**	(23,356)	31,228
Cash and Cash Equivalents, Beginning of Year	**18,498**	41,854	10,626
Cash and Cash Equivalents, End of Year	**$ 28,101**	$ 18,498	$ 41,854

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

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In thousands, except per share amounts)

	Common Shares	Stock Par	Treasury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income / (Loss)[1]	Retained Earnings	Total
Balance at December 31, 2005	100,164	$10,016	3,028	$(39,198)	$392,341	$ (15,115)	$252,167	$ 600,211
Net Income	—	—	—	—	—	—	321,175	321,175
Exercise of Stock Options	876	88	—	—	6,127	—	—	6,215
Purchase of Treasury Stock	—	—	2,177	(46,492)	—	—	—	(46,492)
Tax Benefit of Stock-Based Compensation	—	—	—	—	9,485	—	—	9,485
Stock Amortization and Vesting	378	38	—	—	10,042	—	—	10,080
Cash Dividends at $0.08 per Share	—	—	—	—	—	—	(7,751)	(7,751)
Effect of Adoption of SFAS No. 158	—	—	—	—	—	(14,079)	—	(14,079)
Other Comprehensive Income	—	—	—	—	—	66,354	—	66,354
Balance at December 31, 2006	101,418	$10,142	5,205	$(85,690)	$417,995	$ 37,160	$565,591	$ 945,198
Net Income	—	—	—	—	—	—	167,423	167,423
Exercise of Stock Options	619	62	—	—	5,005	—	—	5,067
Stock Amortization and Vesting	430	43	—	—	7,503	—	—	7,546
Stock Held in Rabbi Trust	214	21	—	—	(6,274)	—	—	(6,253)
Cash Dividends at $0.11 per Share	—	—	—	—	—	—	(10,670)	(10,670)
Other Comprehensive Income	—	—	—	—	—	(38,054)	—	(38,054)
Balance at December 31, 2007	102,681	$10,268	5,205	$(85,690)	$424,229	$ (894)	$722,344	$1,070,257
Net Income	—	—	—	—	—	—	211,290	211,290
Exercise of Stock Options	328	33	—	—	2,692	—	—	2,725
Retirement of Treasury Stock	(5,003)	(500)	(5,003)	82,341	(81,841)	—	—	—
Tax Benefit of Stock-Based Compensation	—	—	—	—	10,691	—	—	10,691
Stock Amortization and Vesting	418	42	—	—	6,545	—	—	6,587
Stock Held in Rabbi Trust	64	6	—	—	(3,198)	—	—	(3,192)
Stock Issued for Drilling Company Acquisition	70	7	—	—	3,493	—	—	3,500
Issuance of Common Stock	5,003	500	—	—	312,957	—	—	313,457
Cash Dividends at $0.12 per Share	—	—	—	—	—	—	(12,073)	(12,073)
Other Comprehensive Income	—	—	—	—	—	187,320	—	187,320
Balance at December 31, 2008	**103,561**	**$10,356**	**202**	**$ (3,349)**	**$675,568**	**$186,426**	**$921,561**	**$1,790,562**

(1) For further details on the components of Accumulated Other Comprehensive Income and Loss, refer to Note 14 of the Notes to the Consolidated Financial Statements.

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

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(In thousands)

	Year Ended December 31,				
	2008		**2007**		**2006**
Net Income		**$211,290**		$167,423	$321,175
Other Comprehensive Income / (Loss), net of taxes:					
Reclassification Adjustment for Settled Contracts, net of taxes of $4,844, $29,801 and $10,686, respectively		**(8,177)**		(49,241)	(17,580)
Changes in Fair Value of Hedge Positions, net of taxes of $(134,259), $(1,777) and $(49,311), respectively		**226,692**		2,555	81,679
Defined Benefit Pension and Postretirement Plans:					
Net Loss Arising During the Year, net of taxes of $10,445 and $1,034, respectively	**$(17,629)**		$(1,733)		
Amortization of Net Obligation at Transition, net of taxes of $(234) and $(238), respectively	**398**		394		
Amortization of Prior Service Cost, net of taxes of $(373) and $(413), respectively	**630**		681		
Amortization of Net Loss, net of taxes of $(603) and $(483), respectively	**1,020**	**(15,581)**	799	141	3,081
Foreign Currency Translation Adjustment, net of taxes of $9,292, $(5,072) and $507, respectively		**(15,614)**		8,491	(826)
Total Other Comprehensive Income / (Loss)		**187,320**		(38,054)	66,354
Comprehensive Income		**$398,610**		$129,369	$387,529

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

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation and Nature of Operations

Cabot Oil & Gas Corporation and its subsidiaries are engaged in the development, exploitation, exploration, 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 development, exploitation and exploration, exclusively within the continental United States and Canada. The Company's exploration activities are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs.

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

On February 23, 2007, the Board of Directors declared a 2-for-1 split of the Company's common stock in the form of a stock distribution. The stock dividend was distributed on March 30, 2007 to stockholders of record on March 16, 2007. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of the Company's common stock.

Recently Issued Accounting Pronouncements

In December 2008, the Securities and Exchange Commission (SEC) issued Release No. 33-8995, "Modernization of Oil and Gas Reporting," which amends the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, as well as adding a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which is being phased out. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 will be required to price proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning January 1, 2010. The Company is currently evaluating what impact Release No. 33-8995 may have on its financial position, results of operations or cash flows.

In June 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. Emerging Issues Task Force (EITF) 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities." Under this FSP, unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents, whether they are paid or unpaid, are considered participating securities and should be included in the computation of earnings per share pursuant to the two-class method. FSP No. EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. In addition, all prior period earnings per share data presented should be adjusted retrospectively and early application is not permitted. The Company does not believe that FSP No. EITF 03-6-1 will have a material impact on its financial position, results of operations or cash flows.

In May 2008, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 162, "The Hierarchy of Generally Accepted Accounting Principles," which identifies a consistent framework for selecting accounting principles to be used in preparing financial statements for nongovernmental entities that are presented in conformity with United States generally accepted accounting principles (GAAP). The current GAAP hierarchy was criticized due to its complexity, ranking position of FASB Statements of Financial Accounting Concepts and the fact that it is directed at auditors rather than entities. SFAS No. 162 will be effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." The FASB does not expect that SFAS No. 162 will have a change in current practice, and the Company does not believe that SFAS No. 162 will have an impact on its financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities," which amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Enhanced disclosures to improve financial reporting transparency are required and include disclosure about the location and amounts of derivative instruments in the financial statements, how derivative instruments are accounted for and how derivatives affect an entity's financial position, financial performance and cash flows. A tabular format including the fair value of derivative instruments and their gains and losses, disclosure about credit risk-related derivative features and cross-referencing within the footnotes are also new requirements. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application and comparative disclosures encouraged, but not required. The Company has not yet adopted SFAS No. 161. It does not believe that there will be an impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations." SFAS No. 141(R) was issued in an effort to continue the movement toward the greater use of fair values in financial reporting and increased transparency through expanded disclosures. It changes how business acquisitions are accounted for and will impact financial statements at the acquisition date and in subsequent periods. Certain of these changes will introduce more volatility into earnings. The acquirer must now record all assets and liabilities of the acquired business at fair value, and related transaction and restructuring costs will be expensed rather than the previous method of being capitalized as part of the acquisition. SFAS No. 141(R) also impacts the annual goodwill impairment test associated with acquisitions, including those that close before the effective date of SFAS No. 141(R). The definitions of a "business" and a "business combination" have been expanded, resulting in more transactions qualifying as business combinations. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 31, 2008 and earlier adoption is prohibited. The Company cannot predict the impact that the adoption of SFAS No. 141(R) will have on its financial position, results of operations or cash flows with respect to any acquisitions completed after December 31, 2008.

Inventories

Inventories are comprised of natural gas in storage, tubular goods and well equipment and pipeline imbalances. All inventory balances are carried at the lower of cost or market. Natural gas in storage is valued at average cost. Tubular goods and well equipment are valued at historical cost.

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. The determination is based on a process which relies on interpretations of available geologic, geophysical, 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. For a discussion of the Company's suspended wells, see Note 2 of the Notes to the Consolidated Financial Statements.

The Company determines if an impairment has occurred through either adverse changes or as a result of a review of all fields. The impairment of unamortized capital costs is measured at a lease level and is reduced to fair value if it is determined that the sum of expected future net cash flows is less than the net book value. During 2008, 2007 and 2006, the Company recorded total impairments of $31.3 million (excluding the impairment of $4.4 million of goodwill), $4.6 million and $3.9 million, respectively.

Development costs of proved oil and gas properties, including estimated dismantlement, restoration and abandonment costs 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 impaired 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. Generally pipeline and transmission systems are depreciated over 12 to 25 years, gathering and compression equipment is depreciated over 10 years and storage equipment and facilities are depreciated over 10 to 16 years. Certain other assets are depreciated on a straight-line basis over 3 to 10 years. Buildings are depreciated on a straight-line basis over 25 years.

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. See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the disposition of the Company's offshore portfolio and certain south Louisiana properties to a third party, which was substantially completed in 2006 (the 2006 south Louisiana and offshore properties sale).

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 of the Notes to the Consolidated Financial Statements 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 with separate counterparties. The Company realized $13.8 million, $11.4 million and $10.3 million of brokered natural gas margin in 2008, 2007 and 2006, 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.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties.

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. These credit balances are referred to as book overdrafts, as a component of Accounts Payable on the Balance Sheet. There were no credit balances from outstanding checks in zero balance cash accounts included in accounts payable at December 31, 2008 and 2007 as sufficient cash was available for offset.

Allowance for Doubtful Accounts

The Company records an allowance for doubtful accounts for receivables that the Company determines to be uncollectible based on the specific identification basis. The allowance for doubtful accounts, which is netted against the accounts receivable line on the Consolidated Balance Sheet, was $3.5 million and $4.0 million at December 31, 2008 and 2007, respectively.

Risk Management Activities

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

When the designated item associated with a derivative instrument matures or 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 of the Notes to the Consolidated Financial Statements for further discussion.

Stock-Based Compensation

The Company follows the provisions of SFAS No. 123(R), "Share Based Payment (revised 2004)." The tax benefit for stock-based compensation is included as both a cash inflow from financing activities and a cash outflow from operating activities in the Consolidated Statement of Cash Flows. In accordance with SFAS No. 123(R), the Company recognizes a tax benefit only to the extent it reduces the Company's income taxes payable. For the years ended December 31, 2008 and 2006, the Company realized tax benefits of $10.7 million and $9.5 million, respectively. For the year ended December 31, 2007, the Company did not recognize a tax benefit for stock-based compensation as a result of the tax net operating loss position for the year under the Alternative Minimum Tax system. See Note 10 of the Notes to the Consolidated Financial Statements for additional details.

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, 2008 and 2007, the cash and cash equivalents are primarily concentrated in two financial institutions. The Company periodically assesses the financial condition of these institutions and considers any possible credit risk to be minimal. Excluded from cash and cash equivalents at December 31, 2007 is $11.6 million of restricted cash. See Note 7 of the Notes to the Consolidated Financial Statements for further details.

Environmental Matters

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

Use of Estimates

In preparing financial statements, the Company follows generally accepted accounting principles. These principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved natural gas, natural gas liquids and crude oil reserves and related cash flow estimates used in impairment tests of oil and gas properties, natural gas, natural gas liquids and crude oil revenues and expenses, current values of derivative instruments, as well as estimates of expenses related to legal, environmental and other contingencies, depreciation, depletion and amortization, pension and postretirement obligations, stock-based compensation and deferred income taxes. Actual results could differ from those estimates.

2. Properties and Equipment, Net

Properties and equipment, net are comprised of the following:

	December 31,	
	2008	**2007**
	(In thousands)	
Unproved Oil and Gas Properties	**$ 315,782**	$ 108,868
Proved Oil and Gas Properties	**3,813,014**	2,627,346
Gathering and Pipeline Systems	**274,192**	235,127
Land, Building and Other Equipment	**68,606**	41,602
	4,471,594	3,012,943
Accumulated Depreciation, Depletion and Amortization	**(1,335,766)**	(1,104,826)
	$ 3,135,828	$ 1,908,117

The provisions of FSP FAS 19-1, "Accounting for Suspended Well Costs," require that, in order for costs to be capitalized, a sufficient quantity of reserves must be discovered in the well to justify its completion as a producing well and that sufficient progress must be made in assessing the well's economic and operating feasibility. If both of these requirements are not met, the costs should be expensed. The following table reflects the net changes in capitalized exploratory well costs during 2008, 2007 and 2006.

	December 31,		
	2008	**2007**	**2006**
	(In thousands)		
Beginning balance at January 1	**$ 2,161**	$ 8,428	$ 6,132
Additions to capitalized exploratory well costs pending the determination of proved reserves	**5,990**	2,161	8,317
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	**(1,259)**	(8,011)	(5,926)
Capitalized exploratory well costs charged to expense	**(902)**	(417)	(95)
Ending balance at December 31	**$ 5,990**	$ 2,161	$ 8,428

At December 31, 2008 and 2007, the Company did not have any projects that had exploratory well costs that were capitalized for a period of greater than one year after drilling. At December 31, 2006, the Company had four projects that had exploratory well costs that were capitalized for a period greater than one year.

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:

	December 31,		
	2008	**2007**	**2006**
	(In thousands)		
Capitalized exploratory well costs that have been capitalized for a period of one year or less	**$5,990**	$2,161	$8,317
Capitalized exploratory well costs that have been capitalized for a period greater than one year	**—**	—	111
Balance at December 31	**$5,990**	$2,161	$8,428
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**—**	—	4

At December 31, 2006, the Company had two wells where the drilling was complete, but a determination of whether proved reserves existed could not be made. Costs associated with these wells have been capitalized for less than one year. One well, located in Canada, completed drilling in September 2006. Subsequent well completion attempts were halted until mid-November 2006, waiting for acceptable weather conditions. The well was completed in the first quarter of 2007. The second well is in the Rocky Mountains area and reached total depth in November 2006. Completion attempts were postponed due to the Bureau of Land Management stipulation which prohibited activity until the summer of 2007. Subsequent completion attempts proved unsuccessful and the costs were expensed in the second quarter of 2007.

Included in the December 31, 2006 amount of exploratory well costs that have been capitalized for a period greater than one year are $0.1 million of costs that have been capitalized since 2005. This amount relates to three projects comprised of preliminary costs incurred in the preparation of well sites where drilling has not commenced as of December 31, 2006. In 2007, it was determined not to drill these projects and associated costs were expensed. Also included in the December 31, 2006 amount was another well that had completed drilling in January 2007 and was awaiting completion results before confirmation of proved reserves could be made. That well was completed in 2007 and proved reserves were recorded in the first quarter of 2007.

During 2008, the Company recorded $31.3 million of impairments of oil and gas properties. The Company recorded an impairment of approximately $3.0 million in the Corral Creek field in Washakie County, Wyoming in the West region resulting from lower than expected performance from the two well field and $28.3 million in the Trawick field in Rusk County, Texas in the Gulf Coast region resulting from a decline in natural gas prices and higher well costs. These fields were reduced to fair market value (using discounted future cash flows) and remain as developmental opportunities for the Company. During 2007, the Company recorded an impairment of approximately $4.6 million in the Castor field in Bienville Parish, Louisiana in the Gulf Coast region resulting from two non-commercial development completions. During 2006, the Company recorded an impairment of $3.9 million. The impairment was recorded on a marginally productive gas well in Colorado County, Texas in the Gulf Coast region. These impairment charges were reflected in the operating results of the Company for each respective period

During 2008, 2007 and 2006, the Company recorded impairments of unproved properties of $41.5 million, $19.0 million and $11.1 million, respectively. Included in 2008 impairments were $17.0 million related to the impairment of three exploratory oil and gas prospects located in Mississippi, Montana and North Dakota. These prospects were impaired as a result of the significant decline in commodity prices in the fourth quarter of 2008 and abandonment of the Company's exploration plans.

In April 2008, the Company acquired a small oilfield services business for total consideration of $21.6 million, comprised of the conversion of a $15.6 million note receivable, the issuance of 70,168 shares of Company common stock, and the payment of $2.5 million in cash. The transaction was accounted for as a business combination, and the Company recorded approximately $4.4 million of goodwill. In December 2008, the Company fully impaired the goodwill due to the impact of the broad economic downturn and the related reductions in future drilling programs.

East Texas Property Acquisition

On August 15, 2008, the Company completed the acquisition of certain producing oil and gas properties located in Panola and Rusk counties, Texas in order to expand its position in the Minden field. Total net cash consideration paid by the Company in the transaction was approximately $604.0 million, which reflects the total gross purchase price of $604.4 million adjusted by $0.4 million comprised of a $1.8 million decrease for the impact of purchase price adjustments, including adjustments based on each party's share of production proceeds received, expenses paid and capital costs incurred for periods before and after the effective date of the acquisition of May 1, 2008, and a $1.4 million increase for the impact of transaction costs, which were primarily legal and accounting costs.

The $604.0 million purchase price was allocated to Properties and Equipment and Other Liabilities (for the asset retirement obligation) as follows:

	(In thousands)
Proved Oil and Gas Properties[1]	$528,813
Unproved Oil and Gas Properties	52,897
Gathering and Pipeline Systems	22,814
Total Assets Acquired	**604,524**
Less:	
Asset Retirement Obligations	(488)
	$604,036

(1) Proved oil and gas properties were determined based on estimated reserves.

The acquired properties are comprised of approximately 25,000 gross leasehold acres with a 97% average working interest near the Company's existing Minden field. Most of the producing properties were operated by the sellers. In addition, the acquisition included a natural gas gathering infrastructure of 31 miles of pipeline, 5,400 horsepower of compression and four water disposal wells. The Company estimates that proved reserves included in the acquisition were approximately 182 Bcfe as of August 1, 2008 (allocated mainly to the Cotton Valley formation).

The east Texas acquisition was recorded using the purchase method of accounting. Financial results for the period from the closing date on August 15, 2008 to December 31, 2008 are included within the Company's 2008 Consolidated Statement of Operations. The following table presents the unaudited pro forma results of operations for the years ended December 31, 2008 and 2007, as if the acquisition was made at the beginning of each period. These pro forma results are not necessarily indicative of future results, nor do they purport to represent the actual financial results that would have occurred had the acquisition been in effect for the periods presented.

	Year Ended December 31,	
	2008	2007
	(Unaudited)	(Unaudited)
	(In thousands, except per share amounts)	
Revenues	**$1,009,412**	$746,089
Net Income	**$ 218,290**	$135,992
Earnings Per Share:		
Basic	**$ 2.12**	$ 1.33
Diluted	**$ 2.10**	$ 1.32
Weighted-Average Common Shares Outstanding:		
Basic	**103,142**	101,981
Diluted	**104,131**	103,133

The Company funded the acquisition with a combination of the net proceeds from its June 2008 sale of approximately five million shares of common stock (see Note 9 of the Notes to the Consolidated Financial Statements) and the net proceeds from its July 2008 private placement of senior unsecured fixed rate notes (see Note 4 of the Notes to the Consolidated Financial Statements). Additionally, in order to mitigate the exposure to price fluctuations of natural gas and crude oil, the Company entered into 12 contracts for natural gas price swaps and three contracts for crude oil swaps in the second quarter of 2008 covering production associated with the acquired properties for the second half of 2008 through 2010 (see Note 11 of the Notes to the Consolidated Financial Statements).

Disposition of Assets

On September 29, 2006, the Company substantially completed the 2006 south Louisiana and offshore properties sale to Phoenix Exploration Company LP for a gross sales price of $340.0 million. The Company received approximately $333.3 million in net proceeds from the sale. In addition to the net gain of $231.2 million ($144.5 million, net of tax) recorded for the year ended December 31, 2006, the Company recorded a net gain of $12.3 million ($7.7 million, net of tax) in the Consolidated Statement of Operations for the year ended December 31, 2007, which included cash proceeds of $5.8 million, $2.1 million in purchase price adjustments and $4.4 million that had been deferred until legal title to certain properties could be assigned.

3. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	**$ 94,164**	$ 94,550
Joint Interest Accounts	**16,454**	16,443
Other Accounts	**1,987**	2,291
	112,605	113,284
Allowance for Doubtful Accounts	**(3,518)**	(3,978)
	$109,087	$109,306
INVENTORIES		
Natural Gas in Storage	**$ 27,478**	$ 20,472
Tubular Goods and Well Equipment	**16,439**	5,953
Pipeline Imbalances	**1,760**	928
	$ 45,677	$ 27,353
OTHER CURRENT ASSETS		
Drilling Advances	**$ 4,869**	$ 2,475
Prepaid Balances	**7,631**	8,900
Restricted Cash	**—**	11,600
Other Accounts	**—**	338
	$ 12,500	$ 23,313
OTHER ASSETS		
Note Receivable	**$ —**	$ 13,375
Rabbi Trust Deferred Compensation Plan	**8,651**	9,744
Other Accounts	**6,092**	8,098
	$ 14,743	$ 31,217
ACCOUNTS PAYABLE		
Trade Accounts	**$ 44,088**	$ 27,678
Natural Gas Purchases	**5,346**	6,465
Royalty and Other Owners	**42,349**	37,023
Capital Costs	**117,029**	83,754
Taxes Other Than Income	**5,617**	6,416
Drilling Advances	**1,289**	1,528
Wellhead Gas Imbalances	**3,354**	3,227
Other Accounts	**3,913**	7,406
	$222,985	$173,497

	December 31, 2008	December 31, 2007
	(In thousands)	
ACCRUED LIABILITIES		
Employee Benefits	**$10,807**	$13,699
Current Liability for Pension Benefits	**245**	116
Current Liability for Postretirement Benefits	**642**	642
Taxes Other Than Income	**16,582**	13,216
Interest Payable	**20,684**	6,518
Litigation	**—**	11,600
Other Accounts	**1,591**	2,274
	$50,551	$48,065
OTHER LIABILITIES		
Rabbi Trust Deferred Compensation Plan	**$14,531**	$16,018
Accrued Plugging and Abandonment Liability	**27,978**	24,724
Other Accounts	**4,717**	6,612
	$47,226	$47,354

4. Debt and Credit Agreements

The Company's debt consisted of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Long-Term Debt		
7.19% Notes	**$ 20,000**	$ 40,000
7.33% Weighted-Average Fixed Rate Notes	**170,000**	170,000
6.51% Weighted-Average Fixed Rate Notes	**425,000**	—
9.78% Notes	**67,000**	—
Credit Facility	**185,000**	140,000
Current Maturities		
7.19% Notes	**(20,000)**	(20,000)
Credit Facility	**(15,857)**	—
Long-Term Debt, excluding Current Maturities	**$831,143**	$330,000

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. The 7.19% Notes require five annual $20 million principal payments which started in November 2005 and are concluding in November 2009. 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

In July 2001, the Company issued $170 million of Notes to a group of seven institutional investors in a private placement. Prior to the determination of the Notes' 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 is being amortized over the life of the Notes, and thereby reducing the effective interest rate by 5.5 basis points. The Notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$75,000,000	10-year	July 2011	7.26%
Tranche 2	$75,000,000	12-year	July 2013	7.36%
Tranche 3	$20,000,000	15-year	July 2016	7.46%

The 7.33% weighted-average fixed rate notes were issued under a substantially similar note purchase agreement as the 7.19% notes and contain the same covenants as discussed above for the 7.19% notes.

6.51% Weighted-Average Fixed Rate Notes

In July 2008, the Company issued $425 million of senior unsecured fixed-rate notes to a group of 41 institutional investors in a private placement. The Notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$245,000,000	10-year	July 2018	6.44%
Tranche 2	$100,000,000	12-year	July 2020	6.54%
Tranche 3	$ 80,000,000	15-year	July 2023	6.69%

Interest on each series of the 6.51% weighted-average fixed rate notes is payable semi-annually. The Company may prepay all or any portion of the Notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The Notes contain restrictions on the merger of the Company 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 plus adjusted cash (as defined in the note purchase agreement) to debt and other liabilities), of 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. The Notes also are subject to customary events of default. The Company is required to offer to prepay the Notes upon specified change in control events accompanied by a ratings decline below investment grade.

9.78% Notes

In December 2008, the Company issued $67 million aggregate principal amount of its 10-year 9.78% Series G Senior Notes to a group of four institutional investors in a private placement. Interest on the Notes is payable semi-annually. The Company may prepay all or any portion of the Notes on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The other terms of the Notes are substantially similar to the terms of the 6.51% Weighted-Average Fixed Rate Notes.

Revolving Credit Agreement

On December 16, 2008, the Company amended its Revolving Credit Agreement (credit facility) with a group of six banks (Class A lenders). Under the amendment, the commitment period for Class A lenders holding approximately 90% of the aggregate commitments of all lenders was extended from December 2009 to October

2010. The outstanding balance under the credit facility for the one lender that is not a Class A lender is reflected in the current portion of long-term debt on the balance sheet. In June 2008, the Company amended the credit facility to increase the borrowings capacity from $250 million to $350 million under the existing accordion feature. At December 31, 2008 and 2007, borrowings outstanding under the credit facility were $185 million and $140 million, respectively. The December 2008 amendment added an accordion feature to allow the Company, if the existing banks or new banks agree, to increase the available credit line from $350 million to $450 million.

The credit facility is unsecured. 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 either to reduce its outstanding debt to the adjusted credit line available with a requirement to provide additional borrowing base assets or to 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 greater than 50%, greater than 75% or greater than 90% of the Company's debt limit of $1.2 billion, as shown below for Class A lenders holding approximately 90% of the aggregate commitments of all lenders:

	Debt Percentage			
	Less than or equal to 50%	**Greater than 50% and less than or equal to 75%**	**Greater than 75% and less than or equal to 90%**	**Greater than 90%**
Euro-Dollar margin	1.750%	2.000%	2.250%	2.500%
Base Rate margin	0.500%	0.750%	1.000%	1.250%
Commitment Fee Rate	0.375%	0.375%	0.500%	0.500%

The credit facility provides for a commitment fee on the unused available balance at annual rates as shown above.

The Company's weighted-average effective interest rates for the credit facility during the years ended December 31, 2008, 2007 and 2006 were approximately 4.8%, 7.2% and 7.9%, respectively. As of December 31, 2008, the weighted-average interest rate on the Company's credit facility was approximately 3.7%.

The credit facility 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.

In addition, the credit facility includes a customary condition to the Company's borrowings under the facility that there has not occurred a material adverse change with respect to the Company.

The Company believes it was in compliance in all material respects with its covenants contained in its various debt agreements at December 31, 2008 and 2007 and during the years then ended.

5. Employee Benefit Plans

Pension Plan

The Company has an underfunded 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 equity securities and fixed income investments. The Company complies with the Employee Retirement Income Security Act (ERISA) of 1974 and Internal Revenue Code limitations when funding the plan.

The Company has an unfunded 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.

Obligations and Funded Status

The funded status represents the difference between the projected benefit obligation of the Company's qualified and non-qualified pension plans and the fair value of the qualified pension plan's assets at December 31.

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

	2008	2007	2006
		(In thousands)	
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	**$ 51,603**	$45,475	$41,211
Service Cost	**3,313**	2,931	2,720
Interest Cost	**3,272**	2,769	2,333
Actuarial Loss	**5,683**	1,314	5
Plan Amendments	**—**	—	(3)
Benefits Paid	**(863)**	(886)	(791)
Benefit Obligation at End of Year	**63,008**	51,603	45,475
Change in Plan Assets			
Fair Value of Plan Assets at Beginning of Year	**44,744**	38,189	23,765
Actual Return on Plan Assets	**(13,682)**	3,179	3,587
Employer Contributions	**5,000**	5,000	12,008
Benefits Paid	**(863)**	(886)	(791)
Expenses Paid	**(904)**	(738)	(380)
Fair Value of Plan Assets at End of Year	**34,295**	44,744	38,189
Funded Status at End of Year	**$(28,713)**	$ (6,859)	$ (7,286)

Amounts Recognized in the Balance Sheet

Amounts recognized in the balance sheet at December 31 consist of the following:

	2008	2007	2006
		(In thousands)	
Current Liabilities	**$ (245)**	$ (116)	$ (67)
Long-Term Liabilities	**(28,468)**	(6,743)	(7,219)
	$(28,713)	$(6,859)	$(7,286)

Amounts Recognized in Accumulated Other Comprehensive Income

Amounts recognized in accumulated other comprehensive income at December 31 consist of the following:

	2008	2007	2006
	(In thousands)		
Prior Service Cost	**$ 143**	$ 194	$ 336
Net Actuarial Loss	**36,373**	13,744	12,946
	$36,516	$13,938	$13,282

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets

	2008	2007	2006
	(In thousands)		
Projected Benefit Obligation	**$63,008**	$51,603	$45,475
Accumulated Benefit Obligation	**$48,050**	$39,544	$34,824
Fair Value of Plan Assets	**$34,295**	$44,744	$38,189

Components of Net Periodic Benefit Cost and Other Amounts Recognized in Other Comprehensive Income Combined Qualified and Non-Qualified Pension Plans

	2008	2007	2006
	(In thousands)		
Components of Net Periodic Benefit Cost			
Current Year Service Cost	**$ 3,313**	$ 2,931	$ 2,721
Interest Cost	**3,272**	2,769	2,333
Expected Return on Plan Assets	**(3,535)**	(3,015)	(1,962)
Amortization of Prior Service Cost	**51**	142	175
Amortization of Net Loss	**1,175**	1,089	1,210
Net Periodic Pension Cost	**$ 4,276**	$ 3,916	$ 4,477
Other Changes in Qualified Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income			
Net Loss	**$23,804**	$ 1,887	N/A
Amortization of Net Loss	**(1,175)**	(1,089)	N/A
Amortization of Prior Service Cost	**(51)**	(142)	N/A
Total Recognized in Other Comprehensive Income	**22,578**	656	N/A
Total Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$26,854**	$ 4,572	N/A

The estimated prior service cost and net loss for the qualified defined benefit pension plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are less than $0.1 million and $2.7 million, respectively.

The estimated prior service cost and net loss for the defined benefit non-qualified pension plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are less than $0.1 million and $0.1 million, respectively.

Assumptions

Weighted-average assumptions used to determine projected pension benefit obligations at December 31 were as follows:

	2008	2007	2006
Discount Rate	**5.75%**	6.00%	5.75%
Rate of Compensation Increase	**4.00%**	4.00%	4.00%

Weighted-average assumptions used to determine net periodic pension costs at December 31 are as follows:

	2008	2007	2006
Discount Rate	**6.00%**	5.75%	5.50%
Expected Long-Term Return on Plan Assets	**8.00%**	8.00%	8.00%
Rate of Compensation Increase	**4.00%**	4.00%	4.00%

The long-term expected rate of return on plan assets used in 2008, as shown above, 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. One of the plan objectives is that performance of the equity portion of the pension plan exceed the Standard and Poors' 500 Index over the long-term. The Company also seeks to achieve a minimum five percent annual real rate of return (above the rate of inflation) on the total portfolio over the long-term. In the Company's pension calculations, the Company has used eight percent as the expected long-term return on plan assets for 2008, 2007 and 2006. In order to derive this return, a Monte Carlo simulation was run using 5,000 simulations based upon the Company's actual asset allocation and liability duration, which has been determined to be approximately 15 years. This model uses historical data for the period of 1926-2007 for stocks, bonds and cash to determine the best estimate range of future returns. The median rate of return, or return that the Company expects to achieve over 50 percent of the time, is approximately nine percent. The Company expects to achieve at a minimum approximately seven percent annual real rate of return on the total portfolio over the long-term at least 75 percent of the time. The Company believes that the eight percent chosen is a reasonable estimate based on its actual results.

Plan Assets

At December 31, 2008 and 2007, the non-qualified pension plan did not have plan assets. The plan assets of the Company's qualified pension plan at December 31, 2008 and 2007, by asset category are as follows:

	2008		2007	
	Amount	Percent	Amount	Percent
	(In thousands)		(In thousands)	
Equity securities	**$23,585**	**69%**	$31,220	70%
Debt securities	**10,398**	**30%**	12,684	28%
Other[(1)]	**312**	**1%**	840	2%
Total	**$34,295**	**100%**	$44,744	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 Company generally targets a portfolio of assets utilizing equity securities, debt securities and cash equivalents that are within a range of approximately 50% to 80% for equity securities and approximately 20% to 40% for fixed income securities. Large capitalization equities may make up a maximum of 65% of the portfolio. Small capitalization equities and international equities may make up a maximum of 30% and 15%, respectively, of the portfolio. Fixed income bonds may make up a maximum of 40% of the portfolio. The account will typically be fully invested; however, as a temporary investment or an asset protection measure, part of the account may be invested in money market investments up to 20%. One percent of the portfolio is invested in short-term funds at the designated bank to meet the cash flow needs of the plan. No prohibited investments, including direct or indirect investments in commodities, commodity futures, derivatives, short sales, real estate investment trusts, letter stock, restricted stock or other private placements, are allowed without prior committee approval.

Cash Flows

Contributions

The funding levels of the pension plans are in compliance with standards set by applicable law or regulation. In 2008, the Company did not have any required minimum funding obligations; however, it chose to fund $5 million into the qualified plan. In 2009, the Company does not have any required minimum funding obligations for the qualified pension plan. The Company will contribute $0.3 million, as shown below, for the non-qualified pension plan. Currently, management has not determined if any additional discretionary funding will be made in 2009.

Estimated Future Benefit Payments

The following estimated benefit payments under the Company's qualified and non-qualified pension plans, which reflect expected future service, as appropriate, are expected to be paid as follows:

	Qualified	Non-Qualified	Total
		(In thousands)	
2009	$ 1,303	$ 252	$ 1,555
2010	1,373	414	1,787
2011	1,599	322	1,921
2012	2,079	738	2,817
2013	2,482	1,374	3,856
Years 2014 - 2018	19,531	2,232	21,763

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. The health care plans are contributory, with participants' contributions adjusted annually. The life insurance plans were non-contributory. As of January 1, 2006, the Company no longer provides postretirement life insurance coverage. Most employees become eligible for these benefits if they meet certain age and service requirements at retirement. The Company was providing postretirement benefits to 234 retirees and their dependents at the end of 2008 and 235 retirees and their dependents at the end of 2007.

When the Company adopted SFAS No. 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 transition obligation are the effects of plan amendments during 1996, 2000 and 2004. As a result of the adoption of SFAS No. 158, the remaining unamortized balance at December 31, 2006 of $3.2 million is now recognized in accumulated other comprehensive income. Additionally, a portion of this amount will be amortized and reclassified from the balance sheet to the income statement as expense each year.

Obligations and Funded Status

The funded status represents the difference between the accumulated benefit obligation of the Company's postretirement plan and the fair value of plan assets at December 31. The postretirement plan does not have any plan assets; therefore, the funded status is equal to the amount of the December 31 accumulated benefit obligation.

The change in the Company's postretirement benefit obligation during the last three years, as well as the funded status at the end of the last three years, is as follows:

	2008	2007	2006
		(In thousands)	
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	**$ 20,846**	$ 18,781	$ 11,793
Service Cost	**1,083**	871	789
Interest Cost	**1,380**	1,076	877
Actuarial Loss	**4,270**	880	6,337
Plan Amendments	**—**	—	(153)
Benefits Paid	**(691)**	(762)	(862)
Benefit Obligation at End of Year	**26,888**	20,846	18,781
Change in Plan Assets			
Fair Value of Plan Assets at End of Year	**N/A**	N/A	N/A
Funded Status at End of Year	**$(26,888)**	$(20,846)	$(18,781)

Amounts Recognized in the Balance Sheet

Amounts recognized in the balance sheet at December 31 consist of the following:

	2008	2007	2006
		(In thousands)	
Current Liabilities	**$ (642)**	$ (642)	$ (577)
Long-Term Liabilities	**(26,246)**	(20,204)	(18,204)
	$(26,888)	$(20,846)	$(18,781)

Amounts Recognized in Accumulated Other Comprehensive Income

Amounts recognized in accumulated other comprehensive income at December 31 consist of the following:

	2008	2007	2006
		(In thousands)	
Transition Obligation	**$ 1,895**	$2,527	$3,159
Prior Service Cost	**666**	1,618	2,570
Net Actuarial Loss	**8,214**	4,392	3,705
	$10,775	$8,537	$9,434

The estimated net obligation at transition, prior service cost and net loss for the defined benefit postretirement plan that will be amortized from accumulated other comprehensive income into net periodic postretirement cost over the next fiscal year are $0.6 million, $0.7 million and $0.5 million, respectively.

Components of Net Periodic Benefit Cost

	2008	2007	2006
	(In thousands)		
Components of Net Periodic Postretirement Benefit Cost			
Current Year Service Cost	**$1,083**	$ 871	$ 789
Interest Cost	**1,380**	1,076	877
Amortization of Prior Service Cost	**952**	952	952
Amortization of Net Obligation at Transition	**632**	632	632
Amortization of Net Loss	**448**	193	32
SFAS 106 Net Periodic Postretirement Cost	**4,495**	3,724	3,282
Recognized Curtailment Gain	**—**	—	(86)
SFAS 88 Cost	**—**	—	(86)
Total SFAS 106 and SFAS 88 Cost	**$4,495**	$3,724	$3,196
Other Changes in Benefit Obligations Recognized in Other Comprehensive Income			
Net Loss	**$4,270**	$ 880	N/A
Amortization of Prior Service Cost	**(952)**	(952)	N/A
Amortization of Net Obligation at Transition	**(632)**	(632)	N/A
Amortization of Net Loss	**(448)**	(193)	N/A
Total Recognized in Other Comprehensive Income	**2,238**	(897)	N/A
Total Recognized in Qualified Net Periodic Benefit Cost and Other Comprehensive Income	**$6,733**	$2,827	N/A

Assumptions

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

	2008	2007	2006
Discount Rate[(1)]	**5.75%**	6.00%	5.75%
Health Care Cost Trend Rate for Medical Benefits Assumed for Next Year	**9.00%**	9.00%	8.00%
Rate to which the cost trend rate is assumed to decline (the Ultimate Trend Rate)	**5.00%**	5.00%	5.00%
Year that the rate reaches the Ultimate Trend Rate	**2013**	2012	2010

(1) Represents the year end rates used to determine the projected benefit obligation. To compute postretirement cost in 2008, 2007 and 2006, respectively, the beginning of year discount rates of 6.0%, 5.75% and 5.5% were used.

Coverage provided to participants age 65 and older is under a fully-insured arrangement. The Company subsidy is limited to 60% of the expected annual fully-insured premium for participants age 65 and older. For all participants under age 65, the Company subsidy for all retiree medical and prescription drug benefits, beginning January 1, 2006, was limited to an aggregate annual amount not to exceed $648,000. This limit increases by 3.5% annually thereafter. The Company prepaid the life insurance premiums for all retirees retiring before January 1, 2006 eliminating all future premiums for retiree life insurance. A life insurance product is offered to employees allowing employees to continue coverage into retirement by paying the premiums directly to the life insurance provider.

Assumed health care cost trend rates may 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:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In thousands)	
Effect on total of service and interest cost	$ 453	$ (366)
Effect on postretirement benefit obligation	4,145	(3,403)

Cash Flows

Contributions

The Company expects to contribute approximately $0.8 million to the postretirement benefit plan in 2009.

Estimated Future Benefit Payments

The following estimated benefit payments under the Company's postretirement plans, which reflect expected future service, as appropriate, are expected to be paid as follows:

	(In thousands)
2009	$ 824
2010	883
2011	974
2012	1,089
2013	1,245
Years 2014 - 2018	8,724

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) introduced 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 amended by the Company on January 1, 2006, the postretirement benefit plan excludes prescription drug benefits to participants age 65 and older. Due to this amendment, FSP No. 106-2 did not have an impact on operating results, financial position or cash flows of the Company.

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 $2.2 million, $2.0 million and $1.8 million in 2008, 2007 and 2006, respectively. The Company matches employee contributions dollar-for-dollar on the first six percent 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. If the employee's base salary and bonus deferrals cause the employee to not receive the full six percent company match to the Savings Investment Plan, the Company will make a contribution annually into the Deferred Compensation Plan to ensure that the employee receives a full matching contribution from the Company. 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.

The officer participants guide the diversification of trust assets. The trust assets are invested in either mutual funds that cover the investment spectrum from equity to money market, or may include holdings of the Company's common stock, which is funded by the issuance of shares to the trust. The mutual funds are publicly traded, have market prices that are readily available and are reported at market value. Settlement payments are made to participants in cash, either in a lump sum or in periodic installments. The market value of the trust assets, excluding the Company's common stock, was $8.7 million and $9.7 million at December 31, 2008 and 2007, respectively, and is included within Other Assets in the Consolidated Balance Sheet. Related liabilities, including the Company's common stock, totaled $14.5 million and $16.0 million at December 31, 2008 and 2007, respectively, and are included within Other Liabilities in the Consolidated Balance Sheet. There is no impact on earnings or earnings per share from the changes in market value of the deferred compensation plan assets, excluding the Company's common stock, because 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.

The Company's common stock held in the rabbi trust is recorded at the market value on the date of deferral, which totaled $9.5 million and $6.3 million at December 31, 2008 and 2007, respectively and is included within Additional Paid-in Capital in Stockholders' Equity in the Consolidated Balance Sheet. As of December 31 2008, 256,400 shares of the Company's stock representing vested performance share awards were deferred into the rabbi trust. During 2008, a reduction to the rabbi trust deferred compensation liability of $4.8 million was recognized, representing the decrease in the closing price of the shares held in the rabbi trust from December 31, 2007 to December 31, 2008. This reduction in stock-based compensation expense was included in General and Administrative expense in the Consolidated Statement of Operations. The Company common stock issued to the trust is not considered outstanding for purposes of calculating basic earnings per share, but is considered a common stock equivalent in the calculation of diluted earnings per share.

The Company charged to expense plan contributions of less than $20,000 in each of 2008, 2007 and 2006.

6. Income Taxes

Income tax expense / (benefit) is summarized as follows:

	Year Ended December 31,		
	2008	**2007**	**2006**
		(In thousands)	
Current			
Federal	**$ 2,631**	$ (1,424)	$123,155
State	**30**	(3,619)	14,164
Total	**2,661**	(5,043)	137,319
Deferred			
Federal	**116,127**	91,257	49,911
State	**5,545**	3,895	2,100
Total	**121,672**	95,152	52,011
Total Income Tax Expense	**$124,333**	$90,109	$189,330

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

	Year Ended December 31,		
	2008	2007	2006
	(Dollars in thousands)		
Statutory Federal Income Tax Rate	**35%**	35%	35%
Computed "Expected" Federal Income Tax	**$117,468**	$90,137	$178,818
State Income Tax, Net of Federal Income Tax Benefit	**6,581**	5,452	14,494
Qualified Production Activities Deduction[1]	**1,174**	—	(2,327)
Benefit Related to Favorable State Tax Determination[2]	**—**	(2,831)	—
Deferred Tax Benefit Related to Reduction in Overall State Tax Rate	**(1,453)**	(1,378)	(2,605)
Other, Net	**563**	(1,271)	950
Total Income Tax Expense	**$124,333**	$90,109	$189,330

(1) Carryback of 2008 regular federal net operating losses reduces the 2006 Qualified Production Activities Deduction.

(2) In November 2007, the Company received a favorable ruling letter related to the computation of income taxes for 2006.

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:

	Year Ended December 31,	
	2008	2007
	(In thousands)	
Deferred Tax Liabilities		
Property, Plant and Equipment	**$644,347**	$472,444
Items Accrued for Financial Reporting Purposes	**6,540**	5,395
Other Comprehensive Income	**132,474**	7,861
Total	**783,361**	485,700
Deferred Tax Assets		
Alternative Minimum Tax Credit	**17,764**	8,587
Net Operating Loss	**40,339**	22,170
Items Accrued for Financial Reporting Purposes	**40,472**	35,193
Other Comprehensive Income	**21,695**	8,353
Total	**120,270**	74,303
Net Deferred Tax Liabilities	**$663,091**	$411,397

As of December 31, 2008, the Company had incurred net operating losses for regular income tax reporting purposes of $153.4 million that it expects to utilize against 2006 taxable income. These losses include $36.1 million of excess tax deductions pursuant to SFAS No. 123(R) not included as deferred tax assets, the benefit of which cannot be recognized until the deductions reduce taxes payable. The Company also had net operating loss carryforwards of $170.7 million for state income tax reporting purposes, the majority of which will expire between 2016 and 2028. It is more likely than not that these deferred tax benefits will be utilized prior to their expiration.

Uncertain Tax Positions

In June 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109." This Interpretation provides guidance for recognizing and measuring uncertain tax positions as defined in SFAS No. 109, "Accounting for Income Taxes." FIN 48 prescribes a two-step process for accounting for income tax uncertainties. First, a threshold condition of "more likely than not" should be met to determine whether any of the benefit of the uncertain tax position should be recognized in the financial statements. If the recognition threshold is met, FIN 48 provides additional guidance on measuring the amount of the uncertain tax position. Under FIN 48, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. Guidance is also provided regarding derecognition, classification, interest and penalties, interim period accounting, transition and increased disclosure of these uncertain tax position. FIN 48 is effective for fiscal years beginning after December 15, 2006.

The Company adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, the Company recognized no change to the liability for unrecognized tax benefits.

The Company recognizes accrued interest related to uncertain tax positions in Interest Expense and Other and accrued penalties related to such positions in General and Administrative expense in the Consolidated Statement of Operations, which is consistent with the recognition of these items in prior reporting periods. As of December 31, 2008, the Company determined that no accrual for penalties was required.

As of December 31, 2008 and 2007, the Company's unrecognized tax benefits were $0.5 million and $2.4 million, respectively. These amounts, if recognized, would not have a significant impact on the effective tax rate.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	Year Ended December 31,	
	2008	**2007**
	(In thousands)	
Unrecognized tax benefit balance at beginning of year	**$ 2,425**	$1,029
Additions based on tax positions related to the current year	**—**	—
Additions for tax positions of prior years	**—**	1,415
Reductions for tax positions of prior years	**(1,925)**	(19)
Settlements	**—**	—
Unrecognized tax benefit balance at end of year	**$ 500**	$2,425

During 2008, the Company executed a final settlement agreement with the Internal Revenue Service that reduced unrecognized tax benefits by $1.9 million. This reduction did not affect the effective tax rate. The amount of remaining unrecognized tax benefits as of December 31, 2008, if recognized, would not have a significant impact on the effective tax rate. It is possible that the amount of unrecognized tax benefits will change in the next twelve months. The Company does not expect that a change would have a significant impact on its results of operations, financial position or cash flows.

The Company files income tax returns in the U.S. federal jurisdiction, various states and Canada. The Company is no longer subject to examinations by state authorities before 2001. The Company is currently under examination by the Internal Revenue Service for 2006.

7. Commitments and Contingencies

Firm Gas Transportation Agreements

The Company has incurred, and will incur over the next several years, demand charges on firm gas transportation agreements. These agreements provide firm transportation capacity rights on pipeline systems in

Canada, the West and East regions. The remaining terms on these agreements range from less than one year to approximately 20 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it can release it to others, thus reducing its potential liability.

Future obligations under firm gas transportation agreements in effect at December 31, 2008 are as follows:

	(In thousands)
2009	$13,218
2010	12,335
2011	11,600
2012	10,024
2013	3,350
Thereafter	44,143
	$94,670

Drilling Rig Commitments

The Company has eight drilling rigs in the Gulf Coast that are under contracts with initial terms of greater than one year. As of December 31, 2008, the Company is obligated under these contracts to pay $44.3 million over the next two years as follows:

	(In thousands)
2009	$42,021
2010	2,250
	$44,271

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 existing office in Houston expires in 2009. During 2008, the Company entered into a lease for new office space in Houston. The new lease will commence in August 2009 and will expire approximately six years from commencement. All other operating leases expire within the next five years, and some of these leases may be renewed. Rent expense under such arrangements totaled $14.6 million, $12.3 million and $10.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2008 are as follows:

	(In thousands)
2009	$ 6,335
2010	4,859
2011	4,169
2012	3,863
2013	3,534
Thereafter	5,926
	$28,686

Contingencies

The Company is a defendant in various legal proceedings arising in the normal course of its business. All known liabilities are accrued based on management's best estimate of the potential loss. While the outcome and impact of such legal proceedings 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 or cash flow. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

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 requested class certification and alleged that the Company failed to pay royalty based upon the wholesale market value of the gas, that the Company had taken improper deductions from the royalty and that it failed to properly inform royalty owners of the deductions. The plaintiffs 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 1995 bankruptcy proceedings. The Court entered an order on June 1, 2005 granting the motion for class certification.

The parties reached a tentative settlement pursuant to which the Company paid a total of $12.0 million into a trust fund for disbursement to the class members upon final approval of the settlement by the Court. The court held the final fairness hearing on February 12, 2008 and approved the settlement, authorized the distribution of the funds to the class members and dismissed all claims against the Company with prejudice. These funds were disbursed in April 2008. Prior to the date of the Court's final order approving the settlement, these restricted cash funds were held by a financial institution in West Virginia under the joint custody of the plaintiffs and the Company. The Company had provided a reserve sufficient to cover the amount agreed upon to settle this litigation. As of June 30, 2008, these funds had been paid out to the class members or were controlled by the Court. Accordingly, the Company had reduced Other Current Assets in the Consolidated Balance Sheet. In the settlement, the Company and the class members also agreed to a methodology for payment of future royalties and the reporting format such methodology will take.

Commitment and Contingency Reserves

When deemed necessary, the Company establishes 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 $2.1 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 or cash flow of the Company. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Settlement of Dispute

In December 2008, the Company settled a dispute with a third party resulting in the Company's recording a gain of $51.9 million, comprised of $20.2 million in cash paid by the third party to the Company and $31.7 million related to the fair value of unproved property rights received.

8. Cash Flow Information

Cash paid / (received) for interest and income taxes is as follows:

	Year Ended December 31,		
	2008	**2007**	**2006**
		(In thousands)	
Interest	**$ 23,089**	$ 20,257	$ 24,088
Income Taxes	**(33,753)**	(20,099)	128,752

9. Capital Stock

Incentive Plans

Under the Company's 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 the first quarter of 2007, the Board of Directors eliminated the automatic award of an option to purchase 30,000 shares of common stock on the date the non-employee directors first join the Board of Directors. In its place, the Board of Directors considers an annual fixed dollar stock award which is competitive with the Company's peer group. A total of 5,100,000 shares of common stock may be issued under the 2004 Incentive Plan. Under the 2004 Incentive Plan, no more than 1,800,000 shares may be used for stock awards that are not subject to the achievement of performance based goals, and no more than 3,000,000 shares may be issued pursuant to incentive stock options.

Stock Issuance

On June 20, 2008, the Company entered into an underwriting agreement, pursuant to which the Company sold an aggregate of 5,002,500 shares of common stock at a price to the Company of $62.66 per share. This aggregate share amount included 652,500 shares of common stock that were issued as a result of the exercise of the underwriters' option to purchase additional shares. On June 25, 2008, the Company closed the public offering and received $313.5 million in net proceeds, after deducting underwriting discounts and commissions. These net proceeds were used temporarily to reduce outstanding borrowings under the Company's revolving credit facility prior to funding a portion of the purchase price of the Company's east Texas acquisition, which closed in the third quarter of 2008.

Immediately prior to (and in connection with) this issuance, the Company retired 5,002,500 shares of its treasury stock, which had a weighted-average purchase price of $16.46, representing $82.3 million. In accordance with the Company's policy, the excess of cost of the treasury stock over its par value was charged entirely to additional paid-in capital.

Stock Split

On February 23, 2007, the Board of Directors declared a 2-for-1 split of the Company's common stock in the form of a stock distribution. The stock dividend was distributed on March 30, 2007 to stockholders of record on March 16, 2007. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of the Company's common stock.

Increase in Authorized Shares

On May 4, 2006, the stockholders of the Company approved an increase in the authorized number of shares of common stock from 80 million to 120 million shares. The Company correspondingly increased the number of shares of Series A Junior Participating Preferred Stock reserved for issuance from 800,000 to 1,200,000. The shares of Series A Junior Participating Preferred Stock are issuable pursuant to the Preferred Stock Purchase Rights Plan described below.

Treasury Stock

The Board of Directors has authorized a share repurchase program under which the Company may purchase shares of common stock in the open market or in negotiated transactions. 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. All purchases executed to date have been through open market transactions. There is no expiration date associated with the authorization to repurchase securities of the Company.

During the year ended December 31, 2008, the Company did not repurchase any shares of common stock. Since the authorization date, the Company has repurchased 5,204,700 shares, or 52% of the 10 million total shares authorized for repurchase at December 31, 2008, for a total cost of approximately $85.7 million. The repurchased shares were held as treasury stock. No treasury shares have been delivered or sold by the Company subsequent to the repurchase. In connection with the June 2008 common stock issuance, the Company retired 5,002,500 shares of its treasury stock as discussed above under the heading "Stock Issuance."

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 or other provision limiting dividends.

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 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 a fraction 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, 2008 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 at any time before a person or group acquires beneficial ownership of 15% of the common stock.

As a result of stock splits in 2005 and 2007, each share of common stock continues to include one right under the Company's Preferred Stock Purchase Rights Plan, and each right now provides for the purchase, upon the occurrence of the conditions set forth in the plan, of one-third of one one-hundredth of a share of preferred stock at a purchase price of approximately $18.33 per one-third of one one-hundredth of a share (or $55 for each one one-hundredth of a share). The redemption price of each right is now one-third of a cent.

10. Stock-Based Compensation

Adoption of SFAS No. 123(R)

Beginning January 1, 2006, the Company began accounting for stock-based compensation under SFAS No. 123(R), which applies to new awards and to awards modified, repurchased or cancelled after December 31, 2005. The Company recorded compensation expense based on the fair value of awards as described below.

Compensation expense charged against income for stock-based awards (including the supplemental employee incentive plans discussed below) for the years ended December 31, 2008, 2007 and 2006 was $34.5 million, $15.3 million and $21.2 million, pre-tax, respectively, and is included in General and Administrative Expense in the Consolidated Statement of Operations. The $0.6 million ($0.4 million, net of tax) cumulative effect charge at adoption that was recorded in the first quarter of 2006 was due primarily to the recording of the liability component of the Company's performance share awards at fair value, rather than intrinsic value.

For the year ended December 31, 2008, the Company realized a $10.7 million tax benefit related to the 2007 federal tax deduction in excess of book compensation cost related to employee stock-based compensation. In accordance with SFAS No. 123(R), the Company is able to recognize this tax benefit only to the extent it reduces the Company's income taxes payable. Such income tax benefit related to the stock-based compensation was recorded in 2008 as the Company carried back net operating losses concurrent with the 2007 tax return filing. For regular tax purposes, the Company was in a net operating loss position in 2008; thus the entire tax benefit related to 2008 employee stock-based compensation will be recorded only when the tax net operating loss is utilized to reduce income taxes payable or claim a refund of taxes paid in prior years. The Company did not recognize a tax benefit related to stock-based compensation in 2007 as a result of the tax net operating loss position for the year under the Alternative Minimum Tax system. A benefit of $9.5 million was recorded for the year ended December 31, 2006 for tax deductions taken due to employee stock option exercises and restricted stock grant vesting. Under SFAS No. 123(R), the tax benefits resulting from tax deductions in excess of expense are reported as an operating cash outflow and a financing cash inflow. For the years ended December 31, 2008 and 2006, $10.7 million and $9.5 million were reported in these two separate line items in the Consolidated Statement of Cash Flows.

During the third quarter of 2006, the Company adopted the provisions outlined under FSP FAS No. 123(R)-3, "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards," which discusses accounting for taxes for stock awards using the APIC Pool concept. The Company was not required to adopt this provision until January 1, 2007, one year from the adoption of 123(R); however, it chose early adoption. The Company made a one time election as prescribed under the FSP to use the shortcut approach to derive the initial windfall tax benefit pool. The Company chose to use a one-pool approach which combines all awards granted to employees, including non-employee directors.

Restricted Stock Awards

Most restricted stock awards vest either at the end of a three year service period, or on a graded-vesting basis of one-third at each anniversary date over a three year service period. Under the graded-vesting approach, the Company recognizes compensation cost over the three year requisite service period for each separately vesting tranche as though the awards are, in substance, multiple awards. For awards that vest at the end of the three year service period, expense is recognized ratably using a straight-line expensing approach over three years. A new award issued in 2008 partially vests at the end of a one year service period, with the remainder vesting at the end of four years. For all restricted stock awards, vesting is dependant upon the employees' continued service with the Company, with the exception of employment termination due to death, disability or retirement.

The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. The maximum contractual term is four years. In accordance with SFAS No. 123(R), the Company accelerated the vesting period for retirement-eligible employees for purposes of recognizing compensation expense in accordance with the vesting provisions of the Company's stock-based compensation programs for awards issued after the adoption of SFAS No. 123(R). The Company used an annual forfeiture rate ranging from 0% to 7.2% based on approximately ten years of the Company's history for this type of award to various employee groups.

The following table is a summary of restricted stock award activity for the year ended December 31, 2008:

Restricted Stock Awards	Shares	Weighted-Average Grant Date Fair Value per share	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)(1)
Non-vested shares outstanding at December 31, 2007	483,494	$18.44		
Granted	13,000	40.93		
Vested	(400,454)	16.24		
Forfeited	(5,100)	25.94		
Non-vested shares outstanding at December 31, 2008	**90,940**	**$30.92**	**2.3**	**$2,364**

(1) The aggregate intrinsic value of restricted stock awards is calculated by multiplying the closing market price of the Company's stock on December 31, 2008 by the number of non-vested restricted stock awards outstanding.

As shown in the table above, there were 13,000 shares of restricted stock granted to employees during 2008. Awards totaling 8,000 shares vest at the end of a one year service period, and awards totaling 5,000 shares vest at the end of a four year service period, both commencing in September 2008. This grant is amortized using a graded-vesting schedule. During the year ended December 31, 2007, 51,900 shares of restricted stock were granted to employees with a weighted-average grant date fair value per share of $32.92. During 2006, 93,700 restricted stock awards were granted with a weighted-average grant date fair value per share of $23.80. The total fair value of shares vested during 2008, 2007 and 2006 was $6.5 million, $5.2 million and $5.0 million, respectively.

Compensation expense recorded for all unvested restricted stock awards for the years ended December 31, 2008, 2007 and 2006 was $1.5 million, $3.4 million and $6.1 million, respectively. Included in 2007 and 2006 restricted stock expense was $0.1 million and $0.6 million, respectively related to the immediate expensing of shares granted to retirement-eligible employees. Unamortized expense as of December 31, 2008 for all outstanding restricted stock awards was $1.2 million and will be recognized over the next 2.3 years.

Restricted Stock Units

Restricted stock units are granted from time to time to non-employee directors of the Company. The fair value of these units is measured at the average of the high and low stock price on grant date and compensation expense is recorded immediately. These units immediately vest and are paid out when the director ceases to be a director of the Company. Due to the immediate vesting of the units and the unknown term of each director, the weighted-average remaining contractual term in years has been omitted from the table below.

The following table is a summary of restricted stock unit activity for the year ended December 31, 2008:

Restricted Stock Units	Shares	Weighted-Average Grant Date Fair Value per share	Aggregate Intrinsic Value (in thousands)[1]
Outstanding at December 31, 2007	85,052	$23.97	
Granted and fully vested	16,565	49.17	
Issued	(19,602)	26.02	
Forfeited	—	—	
Outstanding at December 31, 2008	**82,015**	**$28.57**	**$2,132**

(1) The intrinsic value of restricted stock units is calculated by multiplying the closing market price of the Company's stock on December 31, 2008 by the number of outstanding restricted stock units.

As shown in the table above, 16,565 restricted stock units were granted during 2008. During 2007, 24,654 restricted stock units were granted with a weighted-average grant date fair value per share of $35.49. During 2006, 34,440 restricted stock units were granted with a weighted-average grant date fair value per share of $25.41.

The compensation cost, which reflects the total fair value of these units, recorded in 2008 was $0.8 million. Compensation expense recorded during the years ended December 31, 2007 and 2006 for restricted stock units was $0.9 million for both years.

Stock Options

Stock option awards are granted with an exercise price equal to the market price (defined as the average of the high and low trading prices of the Company's stock at the date of grant) of the Company's stock on the date of grant. During the years ended December 31, 2008 and 2007, there were no stock options granted. During 2006, 60,000 stock options, with an exercise price of $23.80 per share, were granted to two incoming non-employee directors of the Company in the first quarter of 2006.

Compensation cost is recorded based on a graded-vesting schedule as the options vest over a service period of three years, with one-third of the award becoming exercisable each year on the anniversary date of the grant. Stock options have a maximum contractual term of five years. No forfeiture rate is assumed for stock options granted to directors due to the forfeiture rate history for these types of awards for this group of individuals. Compensation expense recorded during 2008, 2007 and 2006 for these stock options was $0.1 million, $0.1 million and $0.3 million, respectively. Unamortized expense as of December 31, 2008 for all outstanding stock options was less than $0.1 million. The weighted-average period over which this compensation will be recognized is approximately 0.2 years.

The grant date fair value of a stock option is calculated by using a Black-Scholes model. The assumptions used in the Black-Scholes fair value calculation for stock options are as follows:

	Year Ended December 31,		
	2008	2007	2006
Weighted-Average Value per Option Granted During the Period[1]	$—	$—	$7.32
Assumptions			
Stock Price Volatility	—	—	31.5%
Risk Free Rate of Return	—	—	4.6%
Expected Dividend	—	—	0.3%
Expected Term (in years)	—	—	4.0

(1) Calculated using the Black-Scholes fair value based method.

The expected term was derived by reviewing minimum and maximum expected term outputs from the Black-Scholes model based on award type and employee type. This term represents the period of time that awards granted are expected to be outstanding. The stock price volatility was calculated using historical closing stock price data for the Company for the period associated with the expected term through the grant date of each award. The risk free rate of return percentages are based on the continuously compounded equivalent of the US Treasury (Nominal 10) within the expected term as measured on the grant date. The expected dividend percentage assumes that the Company will continue to pay a consistent level of dividend each quarter.

The following table is a summary of stock option activity for the years ended December 31, 2008, 2007 and 2006:

	2008		2007		2006	
Stock Options	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at Beginning of Year	388,950	$10.38	1,007,950	$ 9.03	1,826,696	$ 7.66
Granted	—	—	—	—	60,000	23.80
Exercised	(328,450)	8.30	(619,000)	8.18	(876,946)	7.20
Forfeited or Expired	—	—	—	—	(1,800)	9.10
Outstanding at December 31[1]	**60,500**	**$21.69**	388,950	$10.38	1,007,950	$ 9.03
Options Exercisable at December 31[2]	**40,500**	**$20.65**	348,950	$ 8.84	947,950	$ 8.09

(1) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option. The aggregate intrinsic value of options outstanding at December 31, 2008 was $0.3 million. The weighted-average remaining contractual term is 1.8 years.

(2) The aggregate intrinsic value of options exercisable at December 31, 2008 was $0.2 million. The weighted-average remaining contractual term is 1.7 years.

The total intrinsic value of options exercised during the years ended December 31, 2008, 2007 and 2006 was $12.2 million, $19.9 million and $17.7 million, respectively.

Stock Appreciation Rights

Beginning in 2006, the Compensation Committee has granted SARs to employees. These awards allow the employee to receive any intrinsic value over the grant date market price that may result from the price appreciation on a set number of common shares during the contractual term of seven years. All of these awards have graded-vesting features and will vest over a service period of three years, with one-third of the award becoming exercisable each year on the anniversary date of the grant. As these SARs are paid out in stock, rather than in cash, the Company calculates the fair value in the same manner as stock options, by using a Black-Scholes model.

The assumptions used in the Black-Scholes fair value calculation for SARs are as follows:

	Year Ended December 31,		
	2008	**2007**	**2006**
Weighted-Average Value per Stock Appreciation Right Granted During the Period[1]	**$15.18**	$11.26	$7.09
Assumptions			
Stock Price Volatility	**34.4%**	32.6%	31.6%
Risk Free Rate of Return	**2.8%**	4.6%	4.6%
Expected Dividend	**0.2%**	0.2%	0.3%
Expected Term (in years)	**4.25**	4.00	3.75

(1) Calculated using the Black-Scholes fair value based method.

These assumptions were derived using the same process as described in the "Stock Options" section above.

The following table is a summary of SAR activity for the years ended December 31, 2008, 2007 and 2006:

	2008		2007		2006	
Stock Appreciation Rights	**Shares**	**Weighted-Average Exercise Price**	**Shares**	**Weighted-Average Exercise Price**	**Shares**	**Weighted-Average Exercise Price**
Outstanding at Beginning of Year	372,800	$27.08	265,600	$23.80	—	$ —
Granted	119,130	48.48	107,200	35.22	265,600	23.80
Exercised	—	—	—	—	—	—
Forfeited or Expired	—	—	—	—	—	—
Outstanding at December 31[1]	**491,930**	**$32.26**	372,800	$27.08	265,600	$23.80
SARs Exercisable at December 31[2]	**212,790**	**$25.72**	88,526	$23.80	—	$ —

(1) The intrinsic value of a SAR is the amount by which the current market value of the underlying stock exceeds the exercise price of the SAR. The aggregate intrinsic value of SARs outstanding at December 31, 2008 was $0.6 million. The weighted-average remaining contractual term is 4.9 years.

(2) The aggregate intrinsic value of SARs exercisable at December 31, 2008 was $0.4 million. The weighted-average remaining contractual term is 4.3 years.

As shown in the table above, the Compensation Committee granted 119,130 SARs to employees during 2008 with an exercise price equal to the grant date market price of $48.48. The grant date fair value of these SARs was $15.18 per share. Compensation expense recorded during the years ended December 31, 2008, 2007 and 2006 for all outstanding SARs was $1.7 million, $1.5 million and $1.0 million, respectively. Included in both 2008 and 2007 expense was $0.5 million related to the immediate expensing of shares granted to retirement-eligible employees. Unamortized expense as of December 31, 2008 for all outstanding SARs was $0.7 million. The weighted-average period over which this compensation will be recognized is approximately 1.9 years.

Performance Share Awards

During 2008, the Compensation Committee granted three types of performance share awards to employees for a total of 383,065 performance shares. The performance period for two of the three types of these awards commenced on January 1, 2008 and ends December 31, 2010. Both of these types of awards vest at the end of the three year performance period.

Awards totaling 101,830 performance shares are earned, or not 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 performance period. The grant date per share value of the equity portion of this award was $41.53. Depending on the Company's performance, employees may receive an aggregate of up to 100% of the fair market value of a share of common stock payable in common stock plus up to 100% of the fair market value of a share of common stock payable in cash.

Awards totaling 191,400 performance shares were granted and are earned, or not earned, based on the Company's internal performance metrics rather than performance compared to a peer group. As of December 31, 2008, 175,500 shares of this award are outstanding. The grant date per share value of this award was $48.48. These awards represent the right to receive up to 100% of the award in shares of common stock. The actual number of shares issued at the end of the performance period will be determined based on the Company's performance against three performance criteria set by the Company's Compensation Committee. An employee will earn one-third of the award granted for each internal performance metric that the Company meets at the end of the performance period. These performance criteria measure the Company's average production, average finding costs and average reserve replacement over three years. Based on the Company's probability assessment at December 31, 2008, it is considered probable that these three criteria will be met.

The third type of performance share award, totaling 89,835 performance shares, with a grant date per share value of $48.48, has a three-year graded vesting schedule, vesting one-third on each anniversary date following the date of grant, provided that the Company has positive operating income for the year preceding the vesting date. If the Company does not have positive operating income for the year preceding a vesting date, then the portion of the performance shares that would have vested on that date will be forfeited. As of December 31, 2008, it is considered probable that this performance metric will be met.

For all awards granted to employees after January 1, 2006, an annual forfeiture rate ranging from 0% to 4.5% has been assumed based on the Company's history for this type of award to various employee groups.

For awards that are based on the internal metrics (performance condition) of the Company and for awards that were granted prior to the adoption of SFAS No. 123(R) on January 1, 2006, fair value is measured based on the average of the high and low stock price of the Company on grant date and expense is amortized over the three year vesting period. To determine the fair value for awards that were granted after January 1, 2006 that are based on the Company's comparative performance against a peer group (market condition), the equity and liability components are bifurcated. On the grant date, the equity component was valued using a Monte Carlo binomial model and is amortized on a straight-line basis over three years. The liability component is valued at each reporting period by using a Monte Carlo binomial model.

The four primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns, correlation in movement of total shareholder return and the expected dividend. The risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for one and two year bonds and is set equal to the yield, for the period over the remaining duration of the performance period, on treasury securities as of the reporting date. Volatility was set equal to the annualized daily volatility measured over a historic one and two year period ending on the reporting date. Correlation in movement of total shareholder return was determined based on a correlation matrix that was created which identifies total shareholder return correlations for each pair of companies in the peer group, including the Company. The paired returns in the correlation matrix ranged from approximately 71% to approximately 89% for the Company and its peer group. The expected dividend is calculated using the total Company dividends paid ($0.12 for 2008) divided by the December 31, 2008 closing price of the Company's stock ($26.00). Based on these inputs discussed above, a ranking was projected identifying the Company's rank relative to the peer group for each award period.

The following assumptions were used as of December 31, 2008 for the Monte Carlo model to value the liability components of the peer group measured performance share awards. The equity portion of the award was valued on the date of grant using the Monte Carlo model and this portion was not marked to market.

	December 31, 2008
Risk Free Rate of Return	0.4% - 0.8%
Stock Price Volatility	61.8% - 81.9%
Expected Dividend	0.5%

The Monte Carlo value per share for the liability component for all outstanding market condition performance share awards ranged from $9.84 to $17.42 at December 31, 2008. The long-term liability for all market condition performance share awards, included in Other Liabilities in the Consolidated Balance Sheet, at December 31, 2008 and 2007 was $0.3 million and $0.2 million, respectively. The short-term liability, included in Accrued Liabilities in the Consolidated Balance Sheet, at December 31, 2008 and 2007, for certain market condition performance share awards was $2.5 million and $5.5 million, respectively.

On December 31, 2008, the performance period ended for two types of performance shares awarded in 2006, including 155,800 shares measured based on internal performance metrics of the Company and 105,800 shares measured based on the Company's performance against a peer group. For the internal performance metric awards, the calculation of the average of the three years of the Company's three internal performance metrics was completed in the first quarter of 2009 and was certified by the Compensation Committee in February 2009. As the Company achieved the three internal performance metrics, 100% of the award, valued at $3.7 million based on the average of the high and low stock price on the grant date, was payable in 155,800 shares of common stock. For the peer group awards, due to the ranking of the Company compared to its peers in its predetermined peer group, 100% of the award, valued at $1.7 million based on the Monte Carlo value on the grant date, was payable in 105,800 shares of common stock and an additional 67%, equal to two-thirds of the total value of the award, calculated by using the high and low stock price on December 31, 2008 multiplied by the number of performance shares earned, or $1.8 million, was payable in cash. This cash amount was paid in January 2009. The calculation of the award payout was certified by the Compensation Committee on January 5, 2009. The vesting of both types of shares discussed above will be reported in the first quarter of 2009.

The following table is a summary of performance share award activity for the year ended December 31, 2008:

Performance Share Awards	Shares	Weighted-Average Grant Date Fair Value per share[(1)]	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)[(2)]
Non-vested shares outstanding at December 31, 2007	867,700	$25.38		
Granted	383,065	46.63		
Vested	(249,990)	18.55		
Forfeited	(37,000)	36.60		
Non-vested shares outstanding at December 31, 2008	**963,775**	**$35.17**	**1.6**	**$25,058**

(1) The fair value figures in this table represent the fair value of the equity component of the performance share awards.

(2) The aggregate intrinsic value of performance share awards is calculated by multiplying the closing market price of the Company's stock on December 31, 2008 by the number of non-vested performance share awards outstanding.

Of the performance shares that vested during 2008 shown in the table above, 207,800 shares were granted in 2005 and were market condition awards which provided that employees may receive an aggregate of up to 100% of a share of common stock payable in common stock plus up to 100% of the fair market value of a share of common stock payable in cash. As a result of the Company's ranking on the vesting date, 100% of the shares were paid in common stock and an additional 67% of the fair market value of each share of common stock, or $7.9 million, was paid in cash during the second quarter of 2008. Another 30,790 shares vested during 2008 and represent one-third of the three-year graded vesting schedule performance share awards granted in 2007 with a grant date per share value of $35.22. These awards met the performance criteria that the Company had positive operating income for the 2007 year. The remaining 11,400 shares vested as a result of the death of an employee of the Company.

During the year ended December 31, 2007, 387,100 performance share awards were granted with a weighted-average grant date fair value per share of $34.08. During the year ended December 31, 2006, 285,500 performance share awards were granted with a weighted-average grant date fair value per share of $21.07. During the year ended December 31, 2007, 450,000 performance shares vested related to the performance period commencing on January 1, 2004 and ending on December 31, 2007. During the year ended December 31, 2006, 30,600 performance shares vested as a result of the death of one of the Company's officers. During 2007 and 2006, 9,500 and 7,100 performance shares, respectively, were forfeited.

Total unamortized compensation cost related to the equity component of performance shares at December 31, 2008 was $13.5 million and will be recognized over the next 1.6 years, computed by using the weighted-average of the time in years remaining to recognize unamortized expense. Total compensation cost recognized for both the equity (including the cumulative effect) and liability components of performance share awards during the years ended December 31, 2008, 2007 and 2006 was $14.5 million, $9.4 million and $12.9 million, respectively.

Supplemental Employee Incentive Plans

On January 16, 2008, the Company's Board of Directors adopted a Supplemental Employee Incentive Plan. The plan was intended to provide a compensation tool tied to stock market value creation to serve as an incentive and retention vehicle for full-time non-officer employees by providing for cash payments in the event the Company's common stock reaches a specified trading price.

The bonus payout was triggered if, for any 20 trading days (which need not be consecutive) that fell within a period of 60 consecutive trading days occurring on or before November 1, 2011, the closing price per share of the Company's common stock equaled or exceeded the price goal of $60 per share. In such event, the 20th trading day on which such price condition was attained is the "Final Trigger Date." Under the plan, each eligible employee would receive a minimum distribution of 50% of his or her base salary as of the Final Trigger Date, as adjusted for persons hired after December 31, 2007 to reflect calendar quarters of service, reduced by any interim distribution previously paid to such employee upon the achievement of the interim price goal discussed below. The Committee was authorized, in its discretion, to allocate to eligible employees additional distributions, subject to limitations of the plan.

The plan also provided that an interim distribution would be paid to eligible employees upon achieving the interim price goal of $50 per share prior to December 31, 2009. Interim distributions were determined as described above except that interim distributions were based on 10%, rather than 50%, of salary.

On the January 16, 2008 adoption date of the plan, the Company's closing stock price was $40.71. On April 8, 2008 and subsequently on June 2, 2008, the Company achieved the interim and final target goals and total distributions of $15.7 million were paid in 2009. No further distributions will be made under this plan.

On July 24, 2008, the Company's Board of Directors adopted a second Supplemental Employee Incentive Plan ("Plan II"). Plan II is also intended to provide a compensation tool tied to stock market value creation to serve as an incentive and retention vehicle for full-time non-officer employees by providing for cash payments in the event the Company's common stock reaches a specified trading price.

Plan II provides for a final payout if, for any 20 trading days (which need not be consecutive) that fall within a period of 60 consecutive trading days ending on or before June 20, 2012, the closing price per share of the Company's common stock equals or exceeds the price goal of $105 per share. In such event, the 20th trading day on which such price condition is attained is the "Final Trigger Date." The price goal is subject to adjustment by the Compensation Committee to reflect any stock splits, stock dividends or extraordinary cash distributions to stockholders. Under Plan II, each eligible employee may receive (upon approval by the Compensation Committee) a distribution of 50% of his or her base salary as of the Final Trigger Date (or 30% of base salary if the Company paid interim distributions upon the achievement of the interim price goal discussed below).

Plan II provides that a distribution of 20% of an eligible employee's base salary as of the Interim Trigger Date will be made (upon approval by the Compensation Committee) upon achieving the interim price goal of $85 per share on or before June 30, 2010. Interim distributions are determined as described above except that interim distributions will be based on 20%, rather than 50%, of salary. The Compensation Committee can increase the 50% or 20% payment as it applies to any employee.

Payments under either the interim or final distribution will occur as follows:

- 25% of the total distribution paid on the 15th business day following the interim or final trigger date, as applicable, and
- 75% of the total distribution paid based on the following deferred payment dates in the table below:

Period During which the Trigger Date Occurs	Deferred Payment Date
July 1, 2008 to June 30, 2009	The business day on or next following the 18 month anniversary of the applicable Trigger Date
July 1, 2009 to June 30, 2010	The business day on or next following the 12 month anniversary of the applicable Trigger Date
July 1, 2010 to December 31, 2010	The business day on or next following the 6 month anniversary of the applicable Trigger Date
January 1, 2011 to June 30, 2012	No deferral; entire payment is made on the 15th business day following the applicable Trigger Date

Any deferred portion will only be paid if the participant is employed by the Company, or has terminated employment by reason of retirement, death or disability (as provided in Plan II). Payments are subject to certain other restrictions contained in Plan II.

These awards under both plans discussed above have been accounted for as liability awards under SFAS No. 123(R), and the total expense for 2008 was $15.9 million.

11. Financial Instruments

Adoption of SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by United States generally accepted accounting principles to be measured at fair value. SFAS No. 157 clarifies guidance in FASB Concepts Statement (CON) No. 7 which discusses present value techniques in measuring fair value. Additional disclosures are also required for transactions measured at fair value. SFAS

No. 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In February 2008, the FASB issued FSP No. FAS 157-2, "Effective Date of FASB Statement No. 157," which granted a one year deferral (to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years) for certain non-financial assets and liabilities to comply with SFAS No. 157. The Company adopted the provisions of FAS No. 157 covered under FSP No. 157-2 on January 1, 2009. The Company is currently evaluating the impact of implementation with respect to nonfinancial assets and liabilities measured on a nonrecurring basis on its consolidated financial statements, which will primarily be limited to asset impairments including goodwill, other long-lived assets, asset retirement obligations and assets acquired and liabilities assumed in a business combination, if any. Additionally, in February 2008, the FASB issued FSP No. FAS 157-1, "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13," which amends SFAS No. 157 to exclude SFAS No. 13 and related pronouncements that address fair value measurements for purposes of lease classification and measurement. FSP No. FAS 157-1 is effective upon the initial adoption of SFAS No. 157. The Company has adopted SFAS No. 157 and FSP No. FAS 157-1 discussed above, and there was no impact on its financial position or results of operations for the year ended December 31, 2008.

In October 2008, the FASB issued FSP No. FAS 157-3, "Estimating the Fair Value of a Financial Asset in a Market That Is Not Active" to amend SFAS No. 157 to provide guidance regarding how to determine the fair value of a financial asset when there is no active market for the asset at the measurement date. FSP No. FAS 157-3 clarifies how management's internal assumptions, such as internal cash flow and discount rate assumptions, should be considered in measuring fair value when observable data are not present. In addition, observable market information from an inactive market should be considered to determine fair value, and it is inappropriate to conclude that all market activity represents forced liquidations or distressed sales or to conclude that any transaction price can determine fair value. The use of broker quotes and pricing services should also be considered to assess the relevance of observable and unobservable data. When valuing financial assets, significant judgment is required. FSP No. FAS 157-3 was effective upon issuance and has been considered in conjunction with the Company's 2008 financial reporting and results; there was no material impact on the Company's financial position or results of operations for the year ended December 31, 2008.

As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The valuation techniques that can be used under SFAS No. 157 are the market approach, income approach or cost approach. The market approach uses prices and other information for market transactions involving identical or comparable assets or liabilities, such as matrix pricing. The income approach uses valuation techniques to convert future amounts to a single discounted present value amount based on current market conditions about those future amounts, such as present value techniques, option pricing models (i.e. Black-Scholes model) and binomial models (i.e. Monte-Carlo model). The cost approach is based on current replacement cost to replace an asset.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. SFAS No. 157 establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to level 1 measurements and the lowest priority to level 3 measurements, and accordingly, level 1 measurements should be used whenever possible.

The three levels of the fair value hierarchy as defined by SFAS No. 157 are as follows:

- Level 1: Valuations utilizing quoted, unadjusted prices for identical assets or liabilities in active markets that the Company has the ability to access. This is the most reliable evidence of fair value and does not require a significant degree of judgment. Examples include exchange-traded derivatives and listed equities that are actively traded.
- Level 2: Valuations utilizing quoted prices in markets that are not considered to be active or financial instruments for which all significant inputs are observable, either directly or indirectly for substantially the full term of the asset or liability. Financial instruments that are valued using models or other valuation methodologies are included. Models used should primarily be industry-standard models that consider various assumptions and economic measures, such as interest rates, yield curves, time value, volatilities, contract terms, current market prices, credit risk or other market-corroborated inputs. Examples include most over-the-counter derivatives (non-exchange traded), physical commodities, most structured notes and municipal and corporate bonds.
- Level 3: Valuations utilizing significant, unobservable inputs. This provides the least objective evidence of fair value and requires a significant degree of judgment. Inputs may be used with internally developed methodologies and should reflect an entity's assumptions using the best information available about the assumptions that market participants would use in pricing an asset or liability. Examples include certain corporate loans, real-estate and private equity investments and long-dated or complex over-the-counter derivatives.

Depending on the particular asset or liability, input availability can vary depending on factors such as product type, longevity of a product in the market and other particular transaction conditions. In some cases, certain inputs used to measure fair value may be categorized into different levels of the fair value hierarchy. For disclosure purposes under SFAS No. 157, the lowest level that contains significant inputs used in valuation should be chosen. Per SFAS No. 157, the Company has classified its assets and liabilities into these levels depending upon the data relied on to determine the fair values. The fair values of the Company's natural gas and crude oil price collars and swaps are designated as Level 3.

The following fair value hierarchy table presents information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2008:

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2008
		(In thousands)		
Assets				
Rabbi Trust Deferred Compensation Plan	$ 8,651	$—	$ —	**$ 8,651**
Derivative Contracts	—	—	355,202	**355,202**
Total Assets	$ 8,651	$—	$355,202	**$363,853**
Liabilities				
Rabbi Trust Deferred Compensation Plan	$14,531	$—	$ —	**$ 14,531**
Derivative Contracts	—	—	—	**—**
Total Liabilities	$14,531	$—	$ —	**$ 14,531**

The determination of the fair values above incorporates various factors required under SFAS No. 157. These factors include not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's Consolidated Balance Sheet, but also the impact of the Company's nonperformance risk on its liabilities.

The following table sets forth a reconciliation of changes for year ended December 31, 2008 in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	(In thousands)
Balance as of December 31, 2007	$ 7,272[1]
Total Gains or (Losses) (Realized or Unrealized):	
Included in Earnings[2]	13,021
Included in Other Comprehensive Income	347,930
Purchases, Issuances and Settlements	(13,021)
Transfers In and/or Out of Level 3	—
Balance as of December 31, 2008	**$355,202**

(1) Net derivatives for Level 3 at December 31, 2007 included derivative assets of $12.7 million and derivative liabilities of $5.4 million.

(2) All gains included in earnings were realized.

The derivative contracts were measured based on quotes from the Company's counterparties. Such quotes have been derived using a Black-Scholes model that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term. Although the Company utilizes multiple quotes to assess the reasonableness of its values, the Company has not attempted to obtain sufficient corroborating market evidence to support classifying these derivative contracts as Level 2. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions. The resulting reduction to the net receivable derivative contract position was $5.1 million. In times where the Company has net derivative contract liabilities, the nonperformance risk of the Company is evaluated using a market credit spread provided by the Company's bank.

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 fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the year end market rate. The credit spread is the Company's default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company's fixed-rate notes to new issues (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the notes, excluding the credit facility, are 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.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. This disclosure is presented in accordance with SFAS No. 107, "Disclosures about Fair Value of Financial Instruments" as well as SFAS No. 157, "Fair Value Measurements" and does not impact the Company's financial position, results of operations or cash flows.

	December 31, 2008		December 31, 2007	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(In thousands)			
Long-Term Debt	**$867,000**	**$807,508**	$350,000	$364,500
Current Maturities	**(35,857)**	**(35,796)**	(20,000)	(20,466)
Long-Term Debt, excluding Current Maturities	**$831,143**	**$771,712**	$330,000	$344,034

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. The Company's credit agreement restricts the ability of the Company to enter into commodity hedges other than to hedge or mitigate risks to which the Company has actual or projected exposure or as permitted under the Company's risk management policies and not subjecting the Company to material speculative risks. At December 31, 2008, the Company had 26 cash flow hedges open: 14 natural gas price collar arrangements, 10 natural gas price swap arrangements and two crude oil price swap arrangements. At December 31, 2008, a $355.2 million ($223.1 million, net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income / (Loss), along with a $264.7 million short-term derivative receivable and a $90.5 million long-term derivative receivable. The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Accumulated Other Comprehensive Income / (Loss). The ineffective portion of the change in the fair value of derivatives designated as hedges, and the change in fair value of all other derivatives, are recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate Revenue, as appropriate. For the years ended December 31, 2008, 2007 and 2006, there was no ineffectiveness recorded in the Consolidated Statement of Operations.

During the second quarter of 2008, in anticipation of the east Texas acquisition, the Company entered into 12 contracts for natural gas price swaps and three contracts for crude oil swaps (2009 and 2010 contracts included in the amounts discussed above) for the remainder of 2008 and extending through 2010 for the purpose of reducing commodity price risk associated with anticipated production after the transaction closing.

Based upon estimates at December 31, 2008, the Company would expect to reclassify to the Consolidated Statement of Operations, over the next 12 months, $166.2 million in after-tax income associated with commodity hedges. This reclassification represents the net short-term receivable associated with open positions currently not reflected in earnings at December 31, 2008 related to anticipated 2009 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 cash flow hedges are not held for trading purposes. Under these price swaps, the Company receives a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures.

During 2008, natural gas price swaps covered 9,821 Mmcf, or 11%, of the Company's 2008 gas production at an average price of $10.27 per Mcf. During 2008, the Company entered into natural gas price swaps covering a portion of its anticipated 2008, 2009 and 2010 production, including production related to the east Texas acquisition.

At December 31, 2008, the Company had open natural gas price swap contracts covering a portion of its anticipated 2009 and 2010 production as follows:

	Natural Gas Price Swaps		
Contract Period	**Volume in Mmcf**	**Weighted-Average Contract Price (per Mcf)**	**Net Unrealized Gain (In thousands)**
Year Ended December 31, 2009	16,079	$12.18	$90,267
Year Ended December 31, 2010	19,295	$11.43	$70,345

The Company had one crude oil price swap covering 92 Mbbl, or 12%, of its 2008 production at a price of $127.15 per Bbl. During 2008, the Company entered into crude oil price swaps covering a portion of its anticipated 2008, 2009 and 2010 production. At December 31, 2008, the Company had open crude oil price swap contracts covering a portion of its anticipated 2009 and 2010 production as follows:

	Crude Oil Price Swaps		
Contract Period	**Volume in Mbbl**	**Contract Price (per Bbl)**	**Net Unrealized Gain (In thousands)**
Year Ended December 31, 2009	365	$125.25	$25,656
Year Ended December 31, 2010	365	$125.00	$21,840

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 price falls below the floor price, the counterparty pays the Company. During 2008, natural gas price collars covered 54,173 Mmcf of the Company's gas production, or 60% of gas production with a weighted-average floor of $8.53 per Mcf and a weighted-average ceiling of $10.70 per Mcf.

At December 31, 2008, the Company had open natural gas price collar contracts covering a portion of its anticipated 2009 production as follows:

	Natural Gas Price Collars		
Contract Period	**Volume in Mmcf**	**Weighted-Average Ceiling/ Floor (per Mcf)**	**Net Unrealized Gain (In thousands)**
Year Ended December 31, 2009	47,253	$12.39 / $9.40	$152,191

During 2008, an oil price collar covered 366 Mbbls of the Company's crude oil production, or 47% of its crude oil production, with a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl.

The Company is exposed to market risk on these open contracts, to the extent of changes in market prices of natural gas and crude 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 amounts set forth under the net unrealized gain columns in the tables above represent the Company's total unrealized gain position at December 31, 2008. Also impacting the total unrealized net gain (reflecting the net receivable position) in accumulated other comprehensive income / (loss) in the Consolidated Balance Sheet is a reduction of $5.1 million related to the Company's assessment of its counterparties' nonperformance risk. This risk was evaluated by reviewing credit default swap spreads for the various financial institutions in which the Company has derivative transactions.

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" for further details.

Market Risk

The Company's primary market risk is exposure to oil and natural gas prices. Realized prices are mainly driven by worldwide prices for oil and spot market prices for North American natural gas production. Commodity prices are volatile and unpredictable.

The debt and equity markets have recently experienced unfavorable conditions, which may affect the Company's ability to access those markets. As a result of the volatility and disruption in the capital markets and the Company's increased level of borrowings, it may experience increased costs associated with future borrowings and debt issuances. At this time, the Company does not believe its liquidity has been materially affected by the recent market events. The Company will continue to monitor events and circumstances surrounding each of its lenders in its revolving credit facility.

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 2008, one customer accounted for approximately 16% of the Company's total sales. In 2007 and 2006, no customer accounted for more than 10% of the Company's total sales.

12. Asset Retirement Obligations

The Company records the fair value of a liability for an asset retirement obligation 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 majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells. However, liabilities are also recorded for meter stations, pipelines, processing plants and compressors. At December 31, 2008, there were no assets legally restricted for purposes of settling asset retirement obligations.

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 years ended December 31, 2008, 2007 and 2006 was $1.2 million, $1.1 million and $1.4 million, respectively, and was included within Depreciation, Depletion and Amortization expense on the Company's Consolidated Statement of Operations.

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, 2007	$24,724
Liabilities added during the current period	2,157
Liabilities settled during the current period	(101)
Current period accretion expense	1,198
Carrying amount of asset retirement obligations at December 31, 2008	**$27,978**

13. 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 except that the denominator is increased using the treasury stock method to reflect the potential dilution that could occur if 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 years ended December 31, 2008, 2007 and 2006:

	December 31,		
	2008	**2007**	**2006**
Weighted-Average Shares—Basic	**100,736,562**	96,977,634	96,803,283
Dilution Effect of Stock Options and Awards at End of Period	**989,936**	1,152,673	1,797,700
Weighted-Average Shares—Diluted	**101,726,498**	98,130,307	98,600,983
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect	**258,074**	21,639	—

14. Accumulated Other Comprehensive Income / (Loss)

Changes in the components of accumulated other comprehensive income / (loss), net of taxes, for the years ended December 31, 2008, 2007 and 2006 were as follows:

Accumulated Other Comprehensive Income / (Loss), net of taxes (In thousands)	**Net Gains /(Losses) on Cash Flow Hedges**	**Defined Benefit Pension and Postretirement Plans**	**Foreign Currency Translation Adjustment**	**Total**
Balance at December 31, 2005	$ (12,860)	$ (3,170)	$ 915	$ (15,115)
Net change in unrealized gains on cash flow hedges, net of taxes of $(38,625)	64,099	—	—	64,099
Net change in minimum pension liability, net of taxes of $(1,848)	—	3,081	—	3,081
Effect of adoption of SFAS No. 158, net of taxes of $8,447	—	(14,079)	—	(14,079)
Change in foreign currency translation adjustment, net of taxes of $507	—	—	(826)	(826)
Balance at December 31, 2006	$ 51,239	$(14,168)	$ 89	$ 37,160
Net change in unrealized gains on cash flow hedges, net of taxes of $28,024	(46,686)	—	—	(46,686)
Net change in defined benefit pension and postretirement plans, net of taxes of $(100)	—	141	—	141
Change in foreign currency translation adjustment, net of taxes of $(5,072)	—	—	8,491	8,491
Balance at December 31, 2007	$ 4,553	$(14,027)	$ 8,580	$ (894)
Net change in unrealized gain on cash flow hedges, net of taxes of $(129,415)	218,515	—	—	218,515
Net change in defined benefit pension and postretirement plans, net of taxes of $9,235	—	(15,581)	—	(15,581)
Change in foreign currency translation adjustment, net of taxes of $9,292	—	—	(15,614)	(15,614)
Balance at December 31, 2008	**$223,068**	**$(29,608)**	**$ (7,034)**	**$186,426**

CABOT OIL & GAS CORPORATION

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Gas Reserves

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

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

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

Estimates of proved and proved developed reserves at December 31, 2008, 2007, and 2006 were based on studies performed by the Company's petroleum engineering staff. The estimates were computed based on year end prices for oil, natural gas, and natural gas liquids. The estimates were reviewed by Miller and Lents, Ltd., who indicated in their letter dated January 30, 2009, 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, 2008, 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,		
	2008	2007	2006
	(Millions of cubic feet)		
Proved Reserves			
Beginning of Year	**1,559,953**	1,368,293	1,262,096
Revisions of Prior Estimates[1]	**(47,745)**	2,604	(17,675)
Extensions, Discoveries and Other Additions	**297,089**	265,830	246,197
Production	**(90,425)**	(80,475)	(79,722)
Purchases of Reserves in Place	**167,262**	3,701	1,946
Sales of Reserves in Place	**(141)**	—	(44,549)
End of Year	**1,885,993**	1,559,953	1,368,293
Proved Developed Reserves	**1,308,155**	1,133,937	996,850
Percentage of Reserves Developed	**69.4%**	72.7%	72.9%

(1) The majority of the revisions were the result of the decrease in the natural gas price.

	Liquids		
	December 31,		
	2008	2007	2006
	(Thousands of barrels)		
Proved Reserves			
Beginning of Year	**9,328**	7,973	11,463
Revisions of Prior Estimates[1]	**(1,593)**	771	673
Extensions, Discoveries and Other Additions	**1,134**	1,381	1,066
Production	**(794)**	(830)	(1,415)
Purchases of Reserves in Place	**1,268**	33	38
Sales of Reserves in Place	**(2)**	—	(3,852)
End of Year	**9,341**	9,328	7,973
Proved Developed Reserves	**6,728**	7,026	5,895
Percentage of Reserves Developed	**72.0%**	75.3%	73.9%

(1) The majority of the revisions were the result of the decrease in the crude oil price.

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,		
	2008	2007	2006
	(In thousands)		
Aggregate Capitalized Costs Relating to Oil and Gas Producing Activities	**$4,465,630**	$3,007,849	$2,462,693
Aggregate Accumulated Depreciation, Depletion and Amortization	**1,331,243**	1,100,369	983,079

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,		
	2008	2007	2006
	(In thousands)		
Property Acquisition Costs, Proved	**$ 605,860**	$ 3,982	$ 6,688
Property Acquisition Costs, Unproved	**152,666**	22,186	42,551
Exploration Costs[1]	**89,020**	70,242	109,525
Development Costs	**594,221**	494,204	346,787
Total Costs	**$1,441,767**	$590,614	$505,551

(1) Includes administrative exploration costs of $14,766, $13,761 and $13,486 for the years ended December 31, 2008, 2007 and 2006, 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,		
	2008	2007	2006
		(In thousands)	
Operating Revenues	**$829,208**	$637,195	$659,884
Costs and Expenses			
Production	**140,763**	116,020	115,786
Other Operating	**59,348**	40,620	46,212
Exploration[1]	**31,200**	39,772	49,397
Depreciation, Depletion and Amortization	**259,399**	164,613	139,207
Total Costs and Expenses	**490,710**	361,025	350,602
Income Before Income Taxes	**338,498**	276,170	309,282
Provision for Income Taxes	**124,528**	100,755	113,355
Results of Operations	**$213,970**	$175,415	$195,927

(1) Includes administrative exploration costs of $14,766, $13,761 and $13,486 for the years ended December 31, 2008, 2007 and 2006, respectively.

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

The following information has been developed utilizing SFAS No. 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, 2008, 2007 and 2006 for natural gas ($ per Mcf) were $5.66, $6.91 and $5.54, respectively, and for oil ($ per Bbl) were $40.15, $94.94 and $59.50, 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 No. 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 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,		
	2008	2007	2006
		(In thousands)	
Future Cash Inflows	**$11,050,932**	$11,671,078	$ 8,054,737
Future Production Costs	**(3,018,154)**	(2,690,695)	(2,000,993)
Future Development Costs	**(1,354,780)**	(909,374)	(688,955)
Future Income Tax Expenses	**(1,891,928)**	(2,684,271)	(1,763,458)
Future Net Cash Flows	**4,786,070**	5,386,738	3,601,331
10% Annual Discount for Estimated Timing of Cash Flows	**(2,726,115)**	(3,216,087)	(2,125,081)
Standardized Measure of Discounted Future Net Cash Flows(1)	**$ 2,059,955**	$ 2,170,651	$ 1,476,250

(1) The standardized measures of discounted future net cash flows before taxes were $2,365,208, $3,007,661 and $2,010,228 for the years ended December 31, 2008, 2007 and 2006, respectively.

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

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

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Beginning of Year	**$2,170,651**	$1,476,250	$ 2,651,233
Discoveries and Extensions, Net of Related Future Costs	**341,156**	430,918	278,258
Net Changes in Prices and Production Costs	**(692,803)**	864,630	(1,843,272)
Accretion of Discount	**300,766**	201,023	400,177
Revisions of Previous Quantity Estimates	**(69,788)**	13,452	(19,362)
Timing and Other	**(157,194)**	(136,360)	(86,891)
Development Costs Incurred	**157,194**	136,781	85,993
Sales and Transfers, Net of Production Costs	**(688,657)**	(521,558)	(544,650)
Net Purchases / (Sales) of Reserves in Place	**166,873**	8,548	(261,795)
Net Change in Income Taxes	**531,757**	(303,033)	816,559
End of Year	**$2,059,955**	$2,170,651	$ 1,476,250

CABOT OIL & GAS CORPORATION

SELECTED DATA (UNAUDITED)
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	First	Second	Third	Fourth	Total
	(In thousands, except per share amounts)				
2008					
Operating Revenues	**$219,651**	**$248,854**	**$244,820**	**$232,466**	**$945,791**
Impairment of Oil & Gas Properties and Other Assets[1]	**—**	**—**	**—**	**35,700**	**35,700**
Operating Income	**76,072**	**94,086**	**114,717**	**87,137**	**372,012**
Net Income	**45,975**	**54,625**	**66,990**	**43,700**	**211,290**
Basic Earnings per Share	**0.47**	**0.55**	**0.65**	**0.42**	**2.10**
Diluted Earnings per Share	**0.46**	**0.55**	**0.64**	**0.42**	**2.08**
2007					
Operating Revenues	$191,573	$175,832	$170,848	$193,917	$732,170
Impairment of Oil & Gas Properties and Other Assets[1]	—	—	4,614	—	4,614
Operating Income[2]	79,185	70,245	55,521	69,742	274,693
Net Income[2]	48,547	41,376	35,453	42,047	167,423
Basic Earnings per Share	0.50	0.43	0.37	0.43	1.73
Diluted Earnings per Share	0.50	0.42	0.36	0.43	1.71

(1) For discussion of impairment of oil and gas properties, refer to Note 2 of the Notes to the Consolidated Financial Statements.

(2) Operating Income and Net Income in the first and second quarters of 2007 contain the gain on the disposition of offshore and certain south Louisiana properties of $7.9 million and $4.4 million, respectively.

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

As of the end of December 31, 2008, 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 Company in the reports that it files or submits under the Exchange Act.

There were no 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, 2008. 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, 2008, the Company's internal control over financial reporting is effective based on those criteria.

The effectiveness of Cabot Oil & Gas Corporation's internal control over financial reporting as of December 31, 2008, has been audited by Pricewaterhouse Coopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2009 annual stockholders' meeting. In addition, the information set forth under the caption "Business—Other Business Matters—Corporate Governance Matters" in Item 1 regarding our Code of Business Conduct is incorporated by reference in response to this Item.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2009 annual stockholders' meeting.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2009 annual stockholders' meeting.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2009 annual stockholders' meeting.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2009 annual stockholders' meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

A. INDEX

1. Consolidated Financial Statements

See Index on page 56.

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. Our commission file number is 1-10447.

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 May 2, 2007 (Form 10-Q for the quarter ended March 31, 2007).
3.3	Certificate of Amendment of Certificate of Incorporation (Form 8-K for July 1, 2002).
3.4	Certificate of Increase of Shares Designated Series A Junior Participating Preferred Stock (Form 8-K for July 1, 2002).
3.5	Certificate of Amendment of Certificate of Incorporation (Form 8-K for June 1, 2006).
3.6	Certificate of Increase of Shares Designated Series A Junior Participating Preferred Stock (Form 8-K for June 1, 2006).
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, as amended and restated as of December 8, 2000 among the Company and Fleet National Bank formerly known as The First National Bank of Boston and as BankBoston, N.A. (Form 8-K for December 20, 2000). (a) Amendment to the Rights Agreement dated January 1, 2003 (The Bank of New York as rights agent) (Form 10-Q for the quarter ended March 31, 2003). (b) Amendment to the Rights Agreement dated March 30, 2007 (regarding uncertified shares) (Form 10-Q for the quarter ended March 31, 2007).
4.4	Note Purchase Agreement dated November 14, 1997, among the Company and the purchasers named therein (Form 10-K for 1997).

Exhibit Number	Description
4.5	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).
4.6	Credit Agreement dated as of October 28, 2002 among the Company, the Banks Parties Thereto 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 (Form 10-K for 2004). (b) Amendment No. 2 to Credit Agreement dated June 18, 2008 (Form 10-Q for the quarter ended June 30, 2008). (c) Amendment No. 3 to Credit Agreement dated June 18, 2008 (Form 10-Q for the quarter ended June 30, 2008). (d) Amendment No. 4 to Credit Agreement dated December 4, 2008 (Form 8-K for December 16, 2008).
4.7	Note Purchase Agreement dated as of July 16, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 8-K for July 16, 2008).
4.8	Note Purchase Agreement dated as of December 1, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein.
*10.1	Form of Change in Control Agreement between the Company and Certain Officers.
*10.2	Form of Supplemental Executive Retirement Agreement.
*10.3	1990 Non-employee Director Stock Option Plan of the Company (Form S-8) (Registration No. 33-35478). (a) First Amendment to 1990 Non-employee Director Stock Option Plan (Post-Effective Amendment No. 2 to Form S-8) (Registration No. 33-35478). (b) Second Amendment to 1990 Non-employee Director Stock Option Plan (Form 10-K for 1995).
*10.4	Second Amended and Restated 1994 Long-Term Incentive Plan of the Company (Form 10-K for 2001).
*10.5	Second Amended and Restated 1994 Non-Employee Director Stock Option Plan (Form 10-K for 2001).
*10.6	Form of Indemnity Agreement between the Company and Certain Officers (Form 10-K for 1997).
*10.7	Deferred Compensation Plan of the Company, as Amended and Restated, Effective January 1, 2009.
10.8	Trust Agreement dated September 2000 between Harris Trust and Savings Bank and the Company (Form 10-K for 2001).
10.9	Lease Agreement between the Company and DNA COG, Ltd. dated April 24, 1998 (Form 10-K for 1998).
10.10	Credit Agreement dated as of December 17, 1998, between the Company and the banks named therein (Form 10-K for 1998).
*10.11	Employment Agreement between the Company and Dan O. Dinges dated August 29, 2001 (Form 10-K for 2001). (a) Amendment to Employment Agreement between the Company and Dan O. Dinges, effective December 31, 2008.
*10.12	2004 Incentive Plan (Form 10-Q for the quarter ended June 30, 2004). (a) First Amendment to the 2004 Incentive Plan effective February 23, 2007 (Form 10-Q for the quarter ended March 31, 2007). (b) Second Amendment to the 2004 Incentive Plan Amendment, effective as of January 1, 2009.

Exhibit Number	Description
*10.13	2004 Performance Award Agreement (Form 10-Q for the quarter ended June 30, 2004).
*10.14	2004 Annual Target Cash Incentive Plan Measurement Criteria for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
*10.15	Form of Restricted Stock Awards Terms and Conditions for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
*10.16	2005 Form of Non-Employee Director Restricted Stock Unit Award Agreement (Form 8-K for May 24, 2005).
*10.17	Savings Investment Plan of the Company, as amended and restated effective January 1, 2001 (Form 10-K for 2005). (a) First Amendment to the Savings Investment Plan effective January 1, 2002 (Form 10-K for 2005). (b) Second Amendment to the Savings Investment Plan effective January 1, 2003 (Form 10-K for 2005). (c) Third Amendment to the Savings Investment Plan effective January 1, 2005 (Form 10-K for 2005).
*10.18	Forms of Award Agreements for Executive Officers under 2004 Incentive Plan (Form 10-K for 2006). (a) Form of Restricted Stock Award Agreement (Form 10-K for 2006). (b) Form of Stock Appreciation Rights Award Agreement (Form 10-K for 2006). (c) Form of Performance Share Award Agreement (Form 10-K for 2006).
10.19	Cabot Oil & Gas Corporation Mineral, Royalty and Overriding Royalty Interest Plan (Registration Statement No. 333-135365). (a) Form of Conveyance of Mineral and/or Royalty Interest (Registration Statement No. 333-135365). (b) Form of Conveyance of Overriding Royalty Interest (Registration Statement No. 333-135365).
10.20	Purchase and Sale Agreement dated August 25, 2006 between Cabot Oil & Gas Corporation, a Delaware corporation, Cody Energy LLC, a Colorado limited liability company, and Phoenix Exploration Company LP, a Delaware limited partnership (Form 8-K for September 29, 2006).
*10.21	Form of Amendment of Employee Award Agreements (Form 8-K for December 19, 2006).
*10.22	Savings Investment Plan of the Company, as amended and restated effective January 1, 2006 (Form 10-K for 2006). (a) First Amendment to the Savings Investment Plan of the Company effective January 1, 2006 (Form 10-K for 2007). (b) Second Amendment to the Savings Investment Plan of the Company effective April 23, 2008 (Form 10-Q for the quarter ended March 31, 2008). (c) Third Amendment to the Savings Investment Plan of the Company effective July 1, 2008. (d) Fourth Amendment to the Savings Investment Plan of the Company effective January 1, 2008.
*10.23	Pension Plan of the Company, as amended and restated effective January 1, 2006 (Form 10-K for 2006). (a) First Amendment to the Pension Plan of the Company effective January 1, 2006 (Form 10-K for 2007). (b) Second Amendment to the Pension Plan of the Company effective April 23, 2008 (Form 10-Q for the quarter ended March 31, 2008). (c) Third Amendment to the Pension Plan of the Company effective July 1, 2008. (d) Fourth Amendment to the Pension Plan of the Company effective January 1, 2008.

Exhibit Number	Description
10.24	Purchase and Sale Agreement dated June 3, 2008 by and among Enduring Resources, LLC, Mustang Drilling, Inc., Minden Gathering Services, LLC and Cabot Oil & Gas Corporation (Form 10-Q for the quarter ended June 30, 2008).
14.1	Amendment of Code of Business Conduct (as amended on July 28, 2005 to revise Section III. F. relating to Transactions in Securities and Article V. relating to Safety, Health and the Environment) (Form 10-Q for the quarter ended June 30, 2005).
16.1	Letter, dated March 12, 2007, from UHY Mann Frankfort Stein & Lipp CPAs, LLP to the Securities and Exchange Commission (Form 8-K for March 8, 2007).
21.1	Subsidiaries of Cabot Oil & Gas Corporation.
23.1	Consent of PricewaterhouseCoopers LLP.
23.2	Consent of Miller and Lents, Ltd.
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.

* Compensatory plan, contract or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 and 15 (d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on the 27th of February 2009.

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 on behalf of the registrant and 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)	February 27, 2009
/s/ Scott C. Schroeder **Scott C. Schroeder**	Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2009
/s/ Henry C. Smyth **Henry C. Smyth**	Vice President, Controller and Treasurer (Principal Accounting Officer)	February 27, 2009
/s/ Rhys J. Best **Rhys J. Best**	Director	February 27, 2009
/s/ David M. Carmichael **David M. Carmichael**	Director	February 27, 2009
/s/ Robert L. Keiser **Robert L. Keiser**	Director	February 27, 2009
/s/ Robert Kelley **Robert Kelley**	Director	February 27, 2009
/s/ P. Dexter Peacock **P. Dexter Peacock**	Director	February 27, 2009
/s/ William P. Vititoe **William P. Vititoe**	Director	February 27, 2009

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