CABOT OIL & GAS CORP
Form 10-K
February 26, 2010

Table of Contents

Index to Financial Statements

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, 2009

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)**

Three Memorial City Plaza 840 Gessner Road, Suite 1400 Houston, Texas 77024

(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**

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 x 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 x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K [ ].

Indicate by check mark whether the registrant is 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 x	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 x

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, 2009) was approximately $3.2 billion.

As of February 22, 2010, there were 103,821,454 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held April 27, 2010 are incorporated by reference into Part III of this report.

Table of Contents

Index to Financial Statements

TABLE OF CONTENTS

Table of Contents

Index to Financial Statements

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 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, legislative and regulatory initiatives 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

Table of Contents

Index to Financial Statements

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. In 2009, we restructured our operations by combining our Rocky Mountain and Appalachian areas to form the North Region and combining the Anadarko Basin with our Texas and Louisiana areas to form the South Region. Certain prior period amounts and historical descriptions have been reclassified to reflect this reorganization. Operationally, we now have two primary regional offices located in Houston, Texas and Pittsburgh, Pennsylvania.

In 2009, energy commodity prices recovered from the price levels experienced during the second half of 2008. Our 2009 average realized natural gas price was $7.47 per Mcf, 11% lower than the 2008 average realized price of $8.39 per Mcf. Our 2009 average realized crude oil price was $85.52 per Bbl, 4% lower than the 2008 average realized price of $89.11 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 2009, our investment program totaled $640.4 million, including lease acquisition ($145.7 million) and drilling and facilities ($401.1 million) programs. Our capital spending was funded largely through cash flow from operations and, to a lesser extent, borrowings on our revolving credit facility.

We 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 maintain spending discipline and manage our balance sheet in an effort to ensure sufficient liquidity, including cash resources and available credit. We believe these strategies are appropriate for our portfolio of projects and the current industry environment and will continue to add shareholder value over the long-term.

In April 2009, we sold substantially all of our Canadian properties to a private Canadian company (see Note 2 of the Notes to the Consolidated Financial Statements for further details). In April 2009, we also entered into a new revolving credit facility and terminated our prior credit facility (see Note 4 of the Notes to the Consolidated Financial Statements for further details).

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 2009 increased by 8% from 2008. We produced 103.0 Bcfe, or 282.1 Mmcfe per day, in 2009, as compared to 95.2 Bcfe, or 260.1 Mmcfe per day, in 2008. Natural gas production increased to 97.9 Bcf in 2009 from 90.4 Bcf in 2008, primarily due to increased production in the North region associated with the increased drilling program in Susquehanna County, Pennsylvania as well as increased natural gas production in the South region associated with the properties we acquired in the east Texas acquisition in August 2008 and drilling in the Angie field in east Texas. Partially offsetting these production gains were decreases in production in Canada due to the sale of our Canadian properties in April 2009, as well as reduced drilling activity in Oklahoma and Wyoming. Oil production increased by 36 Mbbls from 782 Mbbls in

Table of Contents

Index to Financial Statements

2008 to 818 Mbbls in 2009 due primarily to increased production in the South region associated with the properties we acquired in the east Texas acquisition in August 2008 and an increase related to Pettet development in the Angie field, partially offset by a decrease in production in Canada due to the sale of our Canadian properties in April 2009.

For the year ended December 31, 2009, we drilled 143 gross wells (119 net) with a success rate of 95% compared to 432 gross wells (355 net) with a success rate of 97% for the prior year. In 2010, we plan to drill approximately 136 gross wells (123.9 net), focusing our capital program in the Marcellus Shale in northeast Pennsylvania and, to a lesser extent, in east Texas.

Our 2009 total capital and exploration spending was $640.4 million compared to $1.5 billion of total capital and exploration spending in 2008. In both 2009 and 2008, 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 2010. Funding of the program is expected to be provided by operating cash flow, existing cash and increased borrowings under our credit facility, if required. For 2010, the North region is expected to receive approximately 69% of the anticipated capital program, with the remaining 31% dedicated to the South region. In 2010, we plan to spend approximately $585 million on capital and exploration activities.

Our proved reserves totaled approximately 2,060 Bcfe at December 31, 2009, of which 98% were natural gas. This reserve level was up by 6% from 1,942 Bcfe at December 31, 2008 on the strength of results from our drilling program. In 2009 we had a net downward revision of 200.1 Bcfe primarily due to (i) downward revisions of 101.6 Bcfe due to lower 2009 oil and natural gas prices compared to 2008 and (ii) downward revisions of 120.4 Bcfe due to the removal of proved undeveloped reserves scheduled for development beyond five years primarily due to the application of the Securities and Exchange Commission s (SEC) new oil and gas reserve calculation methodology, partially offset by 21.9 Bcfe of positive performance revisions.

The following table presents certain reserve, production and well information as of December 31, 2009.

	North	South	Total
Proved Reserves at Year End *(Bcfe)*			
Developed	850.0	474.7	**1,324.7**
Undeveloped	496.1	239.1	**735.2**
Total	1,346.1	713.8	**2,059.9**
Average Daily Production *(Mmcfe per day)*	136.6	145.5	**282.1**
Reserve Life Index *(In years)*[1]	27.0	13.4	**20.0**
Gross Wells	4,141	1,753	**5,894**
Net Wells[2]	3,536.9	1,230.2	**4,767.1**
Percent Wells Operated *(Gross)*	88.9%	76.6%	**85.2%**

(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 2.9 million gross acres. In addition, we own fee interest in approximately 0.2 million gross acres, primarily in West Virginia. Our two largest fields, Brachfield Southeast in east Texas and Dimock in Susquehanna County, Pennsylvania, each contain more than 15% of our proved reserves. In addition, we are focusing significant

Table of Contents

Index to Financial Statements

drilling and production activity in the Angie field area of east Texas. These three fields combined make up approximately 43% of our proved reserves.

The following table presents certain information with respect to our principal properties as of and for the year ended December 31, 2009.

	Production Volumes							Average Sales[1] Price		
	Natural Gas (Mcf/ Day)	Oil and NGLs (Bbls/ Day)	Total (Mcfe/Day)	Proved Reserves (Mmcfe)	Gross Producing Wells	Gross Wells Drilled	Nature of Interest (Working/ Royalty)	Natural Gas (Mcf)	Oil and NGLs (Bbl)	Average Production Cost (Mcfe)
Pensylvania										
Dimock (Susquehanna area)	36,227		36,227	458,991	73	51	W	$ 4.27	$	$ 0.03
East Texas										
Brachfield Southeast (Minden area)	35,981	462	38,753	320,835	200	17	W	$ 4.13	$ 51.82	$ 0.65
Angie (County Line area)	35,904	387	38,226	98,168	86	36	W	$ 3.40	$ 66.47	$ 0.27

(1) Excludes the impact of realized derivative instrument settlements.

NORTH REGION

The North region is comprised of the Appalachian and Rocky Mountains areas. In April 2009, we sold substantially all of our Canadian properties to a private Canadian company. Our activities in the Appalachian area are concentrated primarily in northeast Pennsylvania and in West Virginia. Our activities in the Rocky Mountains area are concentrated in the Green River and Washakie Basins in Wyoming and the Paradox Basin in Colorado. This region is managed from our office in Pittsburgh, Pennsylvania. 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 2009 were $380.3 million, or 60% of our total 2009 capital and exploration expenditures, compared to $483.7 million for 2008, or 32% of our total 2008 capital and exploration expenditures. This decrease in spending was substantially driven by a $69.5 million decrease in drilling and facilities costs year-over-year and the sale of our Canadian properties in April 2009. For 2010, we have budgeted approximately $402 million for capital and exploration expenditures in the region.

At December 31, 2009, we had 4,141 wells (3,536.9 net), of which 3,681 wells are operated by us. There are multiple producing intervals in the Appalachian area that include the Big Lime, Weir, Berea and Devonian (including Marcellus) Shale formations at depths primarily ranging from 950 to 9,080 feet, with an average depth of approximately 3,950 feet. In the Rocky Mountains area, principal producing intervals 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 10,950 feet. Average net daily production in 2009 for the North region was 136.6 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2009 was 49.2 Bcf and 125 Mbbls, respectively.

While natural gas production volumes from North region reservoirs are on balance lower on a per-well basis compared to other areas of the United States, the productive life of North region reserves is relatively long. At December 31, 2009, we had 1,346.1 Bcfe of proved reserves (substantially all natural gas) in the North region, constituting 65% of our total proved reserves. Developed and undeveloped reserves made up 850.0 Bcfe and 496.1 Bcfe of the total proved reserves for the North region, respectively.

In 2009, we drilled 62 wells (59.4 net) in the North region, of which 61 wells (59.3 net) were development and extension wells. In 2010, we plan to drill approximately 100 wells (100 net), primarily in the Dimock field in northern Pennsylvania.

In 2009, we produced and marketed approximately 321 barrels of crude oil/condensate/NGL per day in the North region at market responsive prices.

4

Table of Contents

Index to Financial Statements

Ancillary to our exploration, development and production operations, we operated a number of gas gathering and transmission pipeline systems, made up of approximately 3,165 miles of pipeline with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2009. 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 North region. The pipeline systems and storage fields are fully integrated with our operations.

The principal markets for our North region natural gas are in the northeastern and northwestern 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 61% of our natural gas sales volume in the North region is sold at index-based prices under contracts with terms of one to three years. 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 North region production is sold on fixed price contracts that typically renew annually.

SOUTH REGION

Our development, exploitation, exploration and production activities in the South region are primarily concentrated in east and south Texas, Oklahoma and north Louisiana. A regional office in Houston manages the operations. Principal producing intervals are in the Cotton Valley, Haynesville, Pettit and James Lime formations in north Louisiana and east Texas, the Frio, Vicksburg and Wilcox formations in south Texas and the Chase, Morrow and Chester formations in the Anadarko Basin in Oklahoma at depths ranging from 1,300 to 16,970 feet, with an average depth of approximately 8,750 feet.

Capital and exploration expenditures were $237.6 million for 2009, or 37% of our total 2009 capital and exploration expenditures, compared to $1,022.3 million for 2008, or 68% of our total 2008 capital and exploration expenditures. This decrease in capital spending is primarily due to $604.0 million paid in 2008 for the east Texas acquisition and a decrease of $176.9 million in total drilling. Of the total company year-over-year decrease in capital and exploration expenditures, approximately 93% was attributable to the decrease in the South region spending. For 2010, we have budgeted approximately $181 million for capital and exploration expenditures in the region. Our 2010 South region drilling program will emphasize activity primarily in east Texas.

We had 1,753 wells (1,230.2 net) in the South region as of December 31, 2009, of which 1,342 wells are operated by us. Average daily production in 2009 was 145.5 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2009 was 48.8 Bcf and 720 Mbbls, respectively.

Table of Contents

Index to Financial Statements

At December 31, 2009, we had 713.8 Bcfe of proved reserves (95% natural gas) in the South region, which represented 35% of our total proved reserves. Developed and undeveloped reserves made up 474.7 Bcfe and 239.1 Bcfe of the total proved reserves for the South region, respectively.

In 2009, we drilled 81 wells (59.2 net) in the South region, of which 75 wells (55.3 net) were development and extension wells. In 2010, we plan to drill 36 wells (24 net), primarily in east Texas, including the Minden and Angie fields.

Our principal markets for the South region natural gas are in the industrialized Gulf Coast area and the Midwestern United States. We sell natural gas to intrastate pipelines, natural gas processors and marketing companies. Currently, approximately 89% of our natural gas sales volumes in the South region are sold at index-based prices under contracts with terms of one year or greater. The remaining 11% of our sales volumes are sold at index-based prices under short-term agreements. The South region properties are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

In 2009, we produced and marketed approximately 1,966 barrels of crude oil/condensate/NGL per day in the South 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 2009 we employed natural gas and crude oil price collar and swap agreements for portions of our 2009 through 2010 production to attempt to manage price risk more effectively. In addition, we entered into natural gas basis swaps covering a portion of anticipated 2012 production, which do not qualify for hedge accounting. In 2008 and 2007, we employed price collars and swaps 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 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.

For 2009, collars covered 48% of natural gas production and had a weighted-average floor of $9.40 per Mcf and a weighted-average ceiling of $12.39 per Mcf. For 2009, swaps covered 16% of natural gas production and 45% of crude oil production and had a weighted-average price of $12.18 per Mcf and $125.25 per Bbl, respectively.

As of December 31, 2009, we had the following outstanding commodity derivatives:

Commodity	Derivative Type	Weighted-Average Contract Price		Volume		Contract Period
Derivatives designated as Hedging Instruments under ASC 815						
Natural Gas	Swap	$ 9.30	per Mcf	35,856	Mmcf	2010
Crude Oil	Swap	$ 125.00	per Bbl	365	Mbbl	2010
Derivatives not qualifying as Hedging Instruments under ASC 815						
Natural Gas	Basis Swap	$ (0.27)	per Mcf	16,123	Mmcf	2012

Our decision to hedge 2010 and 2012 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.

Table of Contents

Index to Financial Statements

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, 2009.

	Natural Gas (Mmcf)	Liquids[1] (Mbbl)	Total[2][3] (Mmcfe)
Developed:			
North	842,180	1,296	849,955
South	445,989	4,786	474,708
Undeveloped:			
North	495,276	137	496,097
South	229,717	1,564	239,098
Total	**2,013,162**	**7,783**	**2,059,858**

(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 1Bbl of crude oil, condensate or natural gas liquids.

(3) Total proved reserves includes undeveloped reserves that were originally booked more than five years prior to December 31, 2009 that have not yet been developed due to (a) coal mining operations, consisting of 7,972 Mmcfe and 6,057 Mmcfe of reserves booked in 2003 and 2004, respectively, and (b) delays associated with an environmental impact statement required to drill on federal land in Wyoming, consisting of 1,362 Mmcfe and 506 Mmcfe of reserves booked in 1997 and 2001, respectively.

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 made independent estimates for 100% of the proved reserves estimated by us and 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., dated February 12, 2010, has been filed as an exhibit to this Form 10-K. Our reserves are sensitive to natural gas and crude oil sales prices and their effect on the economic productive life of producing properties. Our reserves are based on 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month during 2009. Increases in commodity prices may result in a longer economic productive life of a property or result in more economically viable proved undeveloped reserves to be recognized. Decreases in prices may result in negative impacts of this nature.

Internal Control

Our corporate reservoir engineers report to the Director of Engineering, who maintains oversight and compliance responsibility for the internal reserve estimate process and provides oversight for the annual review of 100% our year-end reserves by our independent third party engineers, Miller and Lents, Ltd. The management of our corporate reservoir engineering group consists of three petroleum/chemical engineers, with petroleum/chemical engineering degrees and between 10 and 27 years of industry experience, between 3 and 27 years of reservoir engineering/management experience, and between 0.5 and 11 years managing our reserves. All are members of the Society of Petroleum Engineers.

7

Table of Contents

Index to Financial Statements

Qualifications of Third Party Engineers

The technical person primarily responsible for review of our reserve estimates at Miller and Lents, Ltd. meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Miller and Lents, Ltd. is an independent firm of petroleum engineers, geologists, geophysicists, and petro physicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

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.

Proved Undeveloped Reserves

At December 31, 2009, we had 735.2 Bcfe of proved undeveloped reserves. During 2009, we converted 70.7 Bcfe of reserves from proved undeveloped to proved developed. An additional 9.6 Bcfe of reserves associated with seven wells drilled in 2009 remain proved undeveloped as a result of the additional capital required to complete the wells. During 2009, total capital related to the development of proved undeveloped reserves was $102.6 million. We had a downward revision of total proved reserves of 200.1 Bcfe primarily due to (i) downward revisions of 101.6 Bcfe due to lower 2009 oil and natural gas prices compared to 2008 and (ii) downward revisions of 120.4 Bcfe due to the removal of proved undeveloped reserves scheduled for development beyond five years primarily due to the application of the SEC s new oil and gas reserve calculation methodology, partially offset by 21.9 Bcfe of positive performance revisions. In accordance with the new rules we priced proved oil and gas reserves using the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month within the 12-month period prior to the end of the reporting period.

As of December 31, 2009 we have 15.9 Bcfe of proved undeveloped reserves, representing less than 1% of our total proved reserves, that will require more than five years to develop due to coal mining operations or delays associated with an environment impact statement required to drill on federal land in Wyoming. An environmental impact study on federal land represents 1.9 Bcfe and the following table summarizes the reserves impacted by mining operations in West Virginia.

Restriction	Year Reserves First Recorded	Net Bcfe	Location
Mining	2003	7.97	West Virginia
Mining	2004	6.06	West Virginia
		14.03	

Table of Contents

Index to Financial Statements

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, 2006(4)	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(4)	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(4)	1,885,993	9,341	1,942,037
Revision of Prior Estimates(3)	(193,767)	(1,062)	(200,143)
Extensions, Discoveries and Other Additions	459,612	544	462,880
Production	(97,914)	(844)	(102,976)
Purchases of Reserves in Place	9		9
Sales of Reserves in Place	(40,771)	(196)	(41,949)
December 31, 2009	**2,013,162**	**7,783**	**2,059,858**
Proved Developed Reserves			
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
December 31, 2009	**1,288,169**	**6,082**	**1,324,663**

(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.

(3) The net downward revision of 200.1 Bcfe was primarily due to (i) downward revisions of 101.6 Bcfe due to lower 2009 oil and natural gas prices compared to 2008 and (ii) downward revisions of 120.4 Bcfe due to the removal of proved undeveloped reserves scheduled for development beyond five years primarily due to the application of the SEC s new oil and gas reserve calculation methodology, partially offset by 21.9 Bcfe of positive performance revisions.

(4) Prior to 2009, reserve estimates were based on year end prices.

Table of Contents

Index to Financial Statements

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,		
	2009	**2008**	**2007**
Net Wellhead Sales Volume			
Natural Gas *(Bcf)*			
North	**48.2**	39.7	38.8
South	**48.8**	46.6	37.8
Canada	**1.0**	4.1	3.9
Crude/Condensate/Ngl *(Mbbl)*			
North	**118**	118	140
South.	**720**	655	672
Canada	**7**	21	18
Equivalents *(Bcfe)*			
North	**48.9**	40.4	39.7
South	**53.1**	50.5	41.8
Canada	**1.0**	4.3	4.0
Produced Natural Gas Sales Price *($/Mcf)*[(1)]			
North	**$ 6.59**	$ 7.95	$ 7.02
South	**8.42**	8.84	7.63
Canada	**3.72**	7.62	5.47
Weighted-Average	**7.47**	8.39	7.23
Produced Crude/Condensate Sales Price *($/Bbl)*[(1)]			
North	**$ 54.11**	$ 93.62	$ 67.37
South	**90.86**	88.46	67.30
Canada	**33.97**	85.08	59.96
Weighted-Average	**85.52**	89.11	67.16
Production Costs *($/Mcfe)*[(2)]			
North	**$ 0.67**	$ 0.80	$ 0.66
South	**0.78**	0.76	0.78
Canada	**1.55**	0.88	0.84
Weighted-Average	**0.74**	0.78	0.73

(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 and insurance, but is exclusive of depreciation and depletion applicable to capitalized lease acquisition, exploration and development expenditures and taxes other than income.

Table of Contents

Index to Financial Statements

Acreage

The following tables summarize our gross and net developed and undeveloped leasehold and mineral acreage at December 31, 2009. 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			197	197	197	197
Arkansas	1,981	425			1,981	425
Colorado	17,640	14,567	152,872	106,396	170,512	120,963
Kansas	28,827	27,505			28,827	27,505
Louisiana	8,318	5,852	7,464	5,574	15,782	11,426
Maryland			1,662	1,662	1,662	1,662
Mississippi			354,203	235,812	354,203	235,812
Montana	397	210	199,391	135,791	199,788	136,001
Nevada			65,260	65,260	65,260	65,260
New York	2,379	961	5,178	4,943	7,557	5,904
North Dakota			25,937	9,706	25,937	9,706
Ohio	6,246	2,384	2,403	1,214	8,649	3,598
Oklahoma	198,639	141,303	54,022	35,702	252,661	177,005
Pennsylvania	118,254	70,177	183,110	182,655	301,364	252,832
Texas	147,574	112,800	121,261	86,939	268,835	199,739
Utah	2,820	1,609	149,735	77,468	152,555	79,077
Virginia	7,130	5,136	2,703	1,649	9,833	6,785
West Virginia	589,988	561,961	205,437	176,175	795,425	738,136
Wyoming	139,509	71,695	112,713	61,981	252,222	133,676
Total	**1,269,702**	**1,016,585**	**1,643,548**	**1,189,124**	**2,913,250**	**2,205,709**
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	97,215	78,543	50,896	49,669	148,111	128,212
Total	**132,503**	**111,126**	**64,344**	**52,594**	**196,847**	**163,720**
Aggregate Total	**1,402,205**	**1,127,711**	**1,707,892**	**1,241,718**	**3,110,097**	**2,369,429**

Total Net Leasehold Acreage by Region of Operation

	Developed	Undeveloped	Total
North	728,700	824,900	1,553,600
South	287,885	364,224	652,109

Total	**1,016,585**	**1,189,124**	**2,205,709**

Table of Contents

Index to Financial Statements

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, 2009. The figures below assume no future successful development or renewal of undeveloped acreage.

	2010	2011	2012
North	176,610	153,650	162,785
South	203,403	91,710	14,871
Total	**380,013**	**245,360**	**177,656**

Well Summary

The following table presents our ownership at December 31, 2009, in productive natural gas and oil wells in the North region (consisting primarily of various fields located in West Virginia, Pennsylvania, Colorado, Utah and Wyoming) and in the South region (consisting primarily of various fields located in Louisiana, Texas, Oklahoma and Kansas) . 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
North	4,104	3,517.8	37	19.1	4,141	3,536.9
South	1,588	1,093.3	165	136.9	1,753	1,230.2
Total	**5,692**	**4,611.1**	**202**	**156.0**	**5,894**	**4,767.1**

(1) Total does not include service wells of 55 (52.6 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, 2009[1]							
	North		South		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells								
Productive	53	51.3	71	52.3			124	103.6
Dry	1	1.0	4	3.0			5	4.0
Extension Wells								
Productive	7	7.0					7	7.0
Dry								
Exploratory Wells								
Productive	1	0.1	4	2.4			5	2.5
Dry			2	1.5			2	1.5
Total	**62**	**59.4**	**81**	**59.2**	**0**	**0.0**	**143**	118.6

Wells Acquired			1	1.0	1	1.0
Wells in Progress at End of Year	10	10.0	6	4.0	16	14.0

(1) In April 2009, we sold substantially all of our Canadian properties.

Table of Contents

Index to Financial Statements

	Year Ended December 31, 2008							
	North		South		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells								
Productive	250	227.2	145	99.7	3	2.0	398	328.9
Dry	1	1.0	7	6.3	1	0.6	9	7.9
Extension Wells								
Productive	3	3.0	2	1.7			5	4.7
Dry	1	1.0					1	1.0
Exploratory Wells								
Productive	3	3.0	11	6.8	2	0.8	16	10.6
Dry	3	1.5					3	1.5
Total	**261**	**236.7**	**165**	**114.5**	**6**	**3.4**	**432**	**354.6**
Wells Acquired			70	68.3			70	68.3
Wells in Progress at End of Year	7	6.3	8	5.0			15	11.3

	Year Ended December 31, 2007							
	North		South		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells								
Productive	295	263.8	129	99.1	5	2.8	429	365.7
Dry	1	1.0	10	8.3			11	9.3
Extension Wells								
Productive	1	1.0	4	3.0	3	1.2	8	5.2
Dry								
Exploratory Wells								
Productive	3	2.8	1	0.5	2	1.2	6	4.5
Dry	3	2.2	4	4.0			7	6.2
Total	**303**	**270.8**	**148**	**114.9**	**10**	**5.2**	**461**	**390.9**
Wells Acquired			2	1.9			2	1.9
Wells in Progress at End of Year	2	2.0	11	6.3	1	0.2	14	8.5

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 North 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 2009, two customers accounted for approximately 13% and 11%, respectively, of the Company s total sales. In 2008, one customer accounted for approximately 16% of the Company s total sales. In 2007, no customer accounted for more than 10% of the Company s total sales.

Table of Contents

Index to Financial Statements

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 (2005 Act), 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

Table of Contents

Index to Financial Statements

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 July 2009, DOT issued a Notice of Proposed Rulemaking to update its reporting requirements for natural gas and hazardous liquid pipelines. On December 3, 2009, DOT adopted a regulation requiring gas and hazardous liquid pipelines that use supervisory control and data acquisition (SCADA) systems and have at least one controller and control room to develop written control room management procedures by August 1, 2011 and implement the procedures by February 1, 2012.

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

Table of Contents

Index to Financial Statements

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 currently do not transport any of our oil or natural gas liquids on a pipeline structured as a master limited partnership.

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.

Table of Contents

Index to Financial Statements

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.

Hydraulic Fracturing. Many of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids usually consisting mostly of water but typically including small amounts of several chemical additives as well as sand into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, bills have recently been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. Moreover, the bills introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. Such disclosure could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. In addition to these federal legislative proposals, some states and local governments have considered imposing various conditions and restrictions on hydraulic fracturing operations, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-

Table of Contents

Index to Financial Statements

volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

Greenhouse Gas. In response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth s atmosphere, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases from sources within the United States between 2012 and 2050. For example, the 110th session of Congress considered various bills that proposed a cap and trade scheme of regulation of greenhouse gas emissions that generally would ban emissions above a defined reducing annual cap. Covered parties would be authorized to emit greenhouse emissions through the acquisition and subsequent surrender of emission allowances that may be traded or acquired on the open market. In addition, at least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs require either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall greenhouse gas emission reduction goal is achieved.

Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of oil or natural gas we produce. Although we would not be impacted to a greater degree than other similarly situated producers of oil and gas, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the oil and gas we produce.

Also, in the wake of the U.S. Supreme Court s decision in April 2007 in Massachusetts v. Environmental Protection Agency, the EPA has begun to regulate carbon dioxide and other greenhouse gas emissions, even though Congress has yet to adopt new legislation specifically addressing emissions of greenhouse gases. In late 2009, the EPA issued a Mandatory Reporting of Greenhouse Gases final rule, which establishes a new comprehensive regulation and reporting scheme for operators of stationary sources emitting certain levels of greenhouse gases, and a Final Rule finding that certain current and projected levels of greenhouse gases in the atmosphere threaten public health and welfare of current and future generations. Please read Item 1A. Risk Factors Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for oil and gas.

Employees

As of December 31, 2009, we had 567 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.

Table of Contents

Index to Financial Statements

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. Requests can also be made in writing to Investor Relations at our corporate headquarters at Three Memorial City Plaza, 840 Gessner Road, Suite 1400, Houston, Texas, 77024.

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 prices have declined from approximately $13 per Mmbtu in mid 2008 to an average price of $3.99 per Mmbtu in 2009. Oil prices have declined from record levels in mid 2008 of approximately $145 per barrel to an average price of $62 per barrel in 2009. The forward price for both natural gas and oil currently stands at rates higher than those realized in 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

Table of Contents

Index to Financial Statements

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

20

Table of Contents

Index to Financial Statements

the estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month 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 (FASB) in Accounting Standards Codification 932 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, 2009 will increase at an estimated rate of 4% during 2010 and then decline at estimated rates of 20%, 12% and 11% during 2011, 2012 and 2013, 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. If an acquired property is not performing as originally estimated, we may have an impairment which could have a material adverse effect on our financial position and results of operations.

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, 2009, 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.

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays.

Bills have recently been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. Moreover, the bills introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. Such disclosure could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. In addition to these federal legislative proposals, some states and local governments have considered imposing various conditions and restrictions on hydraulic fracturing operations, including requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

Table of Contents

Index to Financial Statements

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 5% of our owned net wells, as of December 31, 2009. 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

Table of Contents

Index to Financial Statements

different types of derivatives available, in 2009 we employed natural gas and crude oil price collar and swap agreements for portions of our 2009 through 2010 production to attempt to manage price risk more effectively. In addition, we entered into natural gas basis swaps covering a portion of anticipated 2012 production, which do not qualify for hedge accounting. 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.

Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and gas that we produce.

There is increasing attention in the United States and worldwide concerning the issue of climate change and the effect of greenhouse gases. On September 22, 2009, the EPA issued a Mandatory Reporting of Greenhouse

24

Table of Contents

Index to Financial Statements

Gases final rule (Reporting Rule). The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent greenhouse gases to inventory and report their greenhouse gases emissions annually on a facility-by-facility basis. In addition, on December 15, 2009, the EPA published a Final Rule finding that current and projected concentrations of six key greenhouse gases in the atmosphere threaten public health and the welfare of current and future generations. The EPA also found that the combined emissions of these greenhouse gases from new motor vehicles and new motor vehicle engines contribute to pollution that threatens public health and welfare. This Final Rule, also known as the EPA s Endangerment Finding, does not impose any requirements on industry or other entities directly. However, the EPA must now finalize motor vehicle greenhouse gases standards, the effect of which could reduce demand for motor fuels refined from crude oil. Finally, according to the EPA, the final motor vehicle greenhouse gas standards will trigger construction and operating permit requirements for stationary sources. Moreover, in 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for greenhouse gases, became binding on all those countries that had ratified it. International discussions are currently underway to develop a treaty to replace the Kyoto Protocol after its expiration in 2012. While it is not possible at this time to predict how regulation that may be enacted to address greenhouse gases emissions would impact our business, the modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States in which we operate could materially and adversely affect our operations by limiting drilling opportunities or imposing materially increased costs. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for oil and gas.

The proposed U.S. federal budget for fiscal year 2011 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

On February 1, 2010, the Office of Management and Budget released a summary of the proposed U.S. federal budget for fiscal year 2011. The proposed budget repeals many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposes new taxes. The provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; levy of an excise tax on Gulf of Mexico oil and gas production; repeal of the manufacturing tax deduction for oil and gas companies; and increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities in the U.S. Since none of these proposals have yet to be voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

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. Because of 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 charter.

Table of Contents

Index to Financial Statements

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 charter 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.

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 $0.9 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.

Table of Contents

Index to Financial Statements

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 2009.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information as of February 15, 2010 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	56	Chairman, President and Chief Executive Officer	2001
Michael B. Walen	61	Senior Vice President, Chief Operating Officer	1998
Scott C. Schroeder	47	Vice President and Chief Financial Officer	1997
J. Scott Arnold	56	Vice President, Land and General Counsel	1998
Robert G. Drake	62	Vice President, Information Services and Operational Accounting	1998
Abraham D. Garza	63	Vice President, Human Resources	1998
Jeffrey W. Hutton	54	Vice President, Marketing	1995
Lisa A. Machesney	54	Vice President, Managing Counsel and Corporate Secretary	1995
Phillip L. Stalnaker	50	Vice President, North Region	2009
Henry C. Smyth	63	Vice President, Controller and Treasurer	1998
James M. Reid	58	Vice President, South Region	2009

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.

Phillip L. Stalnaker was elected Vice President and Regional Manager, North Region, in July 2009. From February 2006 to July 2009, Mr. Stalnaker served as Regional Manager for the Western Region and from 2001 to 2006 as Engineering Manager, Western Region. Prior thereto, Mr. Stalnaker served in various capacities of increasing responsibility within the drilling, production and reserve engineering departments at Chevron Corporation.

James M. Reid was elected Vice President and Regional Manager, South Region, in July 2009. From February 2006 to July 2009, Mr. Reid served as Regional Manager, Gulf Coast Region and from 200l to 2006 as Manager, Regional Operation for the Gulf Coast Region. Prior thereto, Mr. Reid served in various operating and engineering positions with Texaco, Inc., Texas Gas Exploration, Total Minatome, Energy Development Corp. and Broughton Operating Corp.

Table of Contents

Index to Financial Statements

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.

	High	Low	Dividends
2009			
First Quarter	**$ 30.76**	**$ 18.14**	**$ 0.03**
Second Quarter	**$ 36.90**	**$ 24.38**	**$ 0.03**
Third Quarter	**$ 39.23**	**$ 27.98**	**$ 0.03**
Fourth Quarter	**$ 45.73**	**$ 34.14**	**$ 0.03**
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

As of February 1, 2010, there were 515 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 2009, 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, 2009 was 4,795,300.

Table of Contents

Index to Financial Statements

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 2004 through December 2009. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2004 and that all dividends were reinvested.

CALCULATED VALUES	2004	2005	2006	2007	2008	2009
S&P 500	100.0	104.9	121.5	128.2	80.7	102.1
COG	100.0	153.5	207.1	276.5	178.6	300.5
Dow Jones US Exploration & Production	100.0	165.3	174.2	250.3	149.9	210.6

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.

Table of Contents

Index to Financial Statements

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,				
	2009	**2008**	**2007**	**2006**	**2005**
	(In thousands, except per share amounts)				
Statement of Operations Data					
Operating Revenues	**$ 879,276**	$ 945,791	$ 732,170	$ 761,988	$ 682,797
Impairment of Oil & Gas Properties and Other Assets[1]	**17,622**	35,700	4,614	3,886	
Gain / (Loss) on Sale of Assets[2]	**(3,303)**	1,143	13,448	232,017	74
Gain on Settlement of Dispute[3]		51,906			
Income from Operations	**282,269**	372,012	274,693	528,946	258,731
Net Income	**148,343**	211,290	167,423	321,175	148,445
Basic Earnings per Share[4]	**$ 1.43**	$ 2.10	$ 1.73	$ 3.32	$ 1.52
Diluted Earnings per Share[4]	**$ 1.42**	$ 2.08	$ 1.71	$ 3.26	$ 1.49
Dividends per Common Share[4]	**$ 0.120**	$ 0.120	$ 0.110	$ 0.080	$ 0.074
Balance Sheet Data					
Properties and Equipment, Net	**$ 3,358,199**	$ 3,135,828	$ 1,908,117	$ 1,480,201	$ 1,238,055
Total Assets	**3,683,401**	3,701,664	2,208,594	1,834,491	1,495,370
Current Portion of Long-Term Debt		35,857	20,000	20,000	20,000
Long-Term Debt	**805,000**	831,143	330,000	220,000	320,000
Stockholders Equity	**1,812,514**	1,790,562	1,070,257	945,198	600,211

(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.

Certain prior year amounts have been reclassified to reflect changes in presenting the geographic areas in which we conduct our operations. These areas consist of the North (comprised of the East and Rocky Mountain areas) and South (comprised of the Gulf Coast and Anadarko areas). In previous periods, we presented the geographic areas as East, Gulf Coast, West and Canada.

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.

30

Table of Contents

Index to Financial Statements

We operate in one segment, natural gas and oil development, exploitation and exploration, exclusively within the United States. In April 2009, we sold substantially all of our Canadian properties to a private Canadian company.

OVERVIEW

Cabot Oil & Gas Corporation is 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 the Continental U.S. 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, we evaluate 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 2009 commodity index prices in general traded in a range significantly below recent highs. However, our realized natural gas and crude oil price was $7.47 per Mcf and $85.52 per Bbl, respectively, in 2009 and were significantly increased by our positions from our derivative instruments, which contributed approximately 45% of our realized revenues in 2009. 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.

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 2008 and 2009. Index represents the first of the month Henry Hub index price per Mmbtu. The 2008 and 2009 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 - 2009											
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Index	**$ 6.16**	**$ 4.49**	**$ 4.07**	**$ 3.65**	**$ 3.33**	**$ 3.54**	**$ 3.96**	**$ 3.37**	**$ 2.84**	**$ 3.72**	**$ 4.28**	**$ 4.49**
2009	**$ 7.72**	**$ 7.32**	**$ 7.46**	**$ 7.03**	**$ 7.28**	**$ 7.45**	**$ 7.50**	**$ 7.45**	**$ 7.25**	**$ 7.42**	**$ 8.03**	**$ 7.75**

	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

Table of Contents

Index to Financial Statements

Prices for crude oil rose to record high levels in 2008, but experienced significant declines in the fourth quarter of 2008. Prices improved during 2009. The tables below contain the NYMEX monthly average crude oil price (Index) and our realized per barrel (Bbl) crude oil prices by month for 2008 and 2009. The 2008 and 2009 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 - 2009											
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Index	**$ 41.92**	**$ 39.26**	**$ 48.06**	**$ 49.95**	**$ 59.21**	**$ 69.70**	**$ 64.29**	**$ 71.14**	**$ 69.47**	**$ 75.82**	**$ 78.15**	**$ 74.60**
2009	**$ 75.41**	**$ 73.98**	**$ 76.29**	**$ 78.86**	**$ 85.94**	**$ 86.26**	**$ 82.22**	**$ 92.16**	**$ 87.54**	**$ 92.13**	**$ 95.35**	**$ 95.41**

	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

We reported earnings of $1.43 per share, or $148.3 million, for 2009, a decrease from the $2.10 per share, or $211.3 million, reported in 2008. Natural gas revenues decreased from 2008 to 2009 as a result of decreased commodity market prices, partially offset by increased natural gas production and favorable natural gas hedge settlements. Crude oil revenues remained flat from 2008 to 2009 primarily due to increased crude oil production and favorable oil hedge settlements, offset by a decrease in realized prices. Prices, including the realized impact of derivative instruments, decreased by 11% for natural gas and 4% for oil.

We drilled 143 gross wells with a success rate of 95% in 2009 compared to 432 gross wells with a success rate of 97% in 2008. Total capital and exploration expenditures decreased by $840.6 million to $640.4 million in 2009 compared to $1,481.0 million (including the east Texas acquisition) in 2008. This decrease was largely due to the $604 million acquisition of east Texas assets in 2008 and a decrease of $231.9 million in total drilling. We believe our cash on hand and operating cash flow in 2010 will be sufficient to fund our budgeted capital and exploration spending of approximately $585 million. Any additional needs are expected to be funded by borrowings from our credit facility.

Our 2010 strategy will remain consistent with 2009. 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 maintain spending discipline and manage our balance sheet in an effort to ensure sufficient liquidity, including cash resources and available credit. In the current year we have allocated our planned program for capital and exploration expenditures primarily to the Marcellus Shale in northeast Pennsylvania, and to a lesser extent east Texas. We believe these strategies are appropriate for our portfolio of projects and the current industry environment and 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 2009 were from funds generated from the sale of natural gas and crude oil production (including hedge realizations) and, to a lesser extent, the sales of properties during the year and borrowings under our revolving credit facility. These cash flows were primarily used to fund our development and exploratory expenditures, in addition to payments for debt service, debt issuance costs, contributions to our pension plan and dividends. See below for additional discussion and analysis of cash flow.

Table of Contents

Index to Financial Statements

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. We believe we have adequate credit availability and liquidity available to meet our working capital requirements.

	Year Ended December 31,		
	2009	**2008**	**2007**
		(In thousands)	
Cash Flows Provided by Operating Activities	**$ 614,052**	$ 634,447	$ 462,137
Cash Flows Used in Investing Activities	**(531,027)**	(1,452,289)	(589,922)
Cash Flows Provided by / (Used in) Financing Activities	**(70,968)**	827,445	104,429
Net Increase / (Decrease) in Cash and Cash Equivalents	**$ 12,057**	$ 9,603	$ (23,356)

Operating Activities. Key components impacting net operating cash flows are commodity prices, production volumes and operating costs. Net cash provided by operating activities in 2009 decreased by $20.4 million over 2008. This decrease was mainly due to a decrease in oil and gas revenues, partially offset by lower operating, interest and tax expense. Average realized natural gas prices decreased by 11% in 2009 compared to 2008 and average realized crude oil prices decreased by 4% over the same period. Equivalent production volumes increased by 8% in 2009 compared to 2008 as a result of higher natural gas and crude oil 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 continue to decline during 2010.

For 2009, we had natural gas price swaps covering 16.1 Bcf of our 2009 gas production at an average price of $12.18 per Mcf and natural gas price collars covering 47.3 Bcf of our 2009 gas production, with a weighted-average floor of $9.40 per Mcf and a weighted-average ceiling of $12.39 per Mcf. As of December 31, 2009, we have natural gas price swaps covering 19.3 Bcf of our 2010 gas production at an average price of $9.30 per Mcf, and no natural gas price collars. Accordingly, based on our current hedge position, we will be more subject to the effects of natural gas price volatility in 2010 than in 2009. In addition, given the current market for derivatives, if we were to hedge all our 2010 production, we would expect our realized prices to be lower than our 2009 realized prices.

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.

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 and exploration expenses. We established the budget for these amounts based on our current estimate of future commodity prices

Table of Contents

Index to Financial Statements

and cash flows. 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 decreased by $921.3 million from 2008 to 2009 and increased by $862.4 million from 2007 to 2008. The decrease from 2008 to 2009 was due to a decrease of $862.8 million in acquisitions and capital expenditures and an increase of $78.1 million of proceeds from the sale of assets, partially offset by an increase of $19.6 million in exploration expenditures. In August 2008, we completed the acquisition of producing properties, leasehold acreage and a natural gas gathering infrastructure in east Texas for total net cash consideration of approximately $604.0 million.

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.

Financing Activities. Cash flows provided by financing activities decreased by $898.4 million from 2008 to 2009. This was primarily due to a decrease in borrowings from debt of $787 million, partially offset by a decrease in repayments of debt of $208 million, and a decrease in net proceeds from the sale of common stock of $316.1 million primarily due to our June 2008 issuance of 5,002,500 shares of common stock in a public offering. Common stock proceeds and debt borrowings in 2008 were largely used to finance the acquisition of east Texas properties and undeveloped acreage. Cash paid for capitalized debt issuance costs and dividends increased by a total of $6.4 million, partially offset by an increase of $3.1 million in the tax benefit associated with stock-based compensation.

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.

At December 31, 2009, we had $143 million of borrowings outstanding under our unsecured credit facility at a weighted-average interest rate of 3.9%. In April 2009, we entered into a new revolving credit facility and terminated our prior credit facility. The new credit facility provides for an available credit line of $500 million and contains an accordion feature allowing us to increase the available credit line to $600 million, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. 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 based on our reserve reports and engineering reports) and certain other assets and the outstanding principal balance of our senior notes. 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, with internally generated cash, existing cash and availability under our revolving credit facility, we have the capacity to finance our spending plans and maintain our strong financial position. At the same time, we will closely monitor the capital markets.

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. We received $313.5 million in net

Table of Contents

Index to Financial Statements

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, 2009	December 31, 2008
	(Dollars in millions)	
Debt[1]	**$ 805.0**	$ 867.0
Stockholders Equity	**1,812.5**	1,790.6
Total Capitalization	**$ 2,617.5**	$ 2,657.6
Debt to Capitalization	**31%**	33%
Cash and Cash Equivalents	**$ 40.2**	$ 28.1

(1) Includes $35.9 million of current portion of long-term debt at December 31, 2008. Includes $143 million and $185 million of borrowings outstanding under our revolving credit facility at December 31, 2009 and 2008, respectively.

For the year ended December 31, 2009, we paid dividends of $12.4 million ($0.03 per share) on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990.

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, 2009.

	2009	2008	2007
		(In millions)	
Capital Expenditures			
Drilling and Facilities[1]	**$ 401.1**	$ 624.3	$ 539.7
Leasehold Acquisitions	**145.7**	152.7	22.2
Acquisitions	**0.4**	625.0	4.0
Pipeline and Gathering	**32.9**	36.9	28.2
Other	**9.5**	10.9	2.3
	589.6	1,449.8	596.4
Exploration Expense	**50.8**	31.2	39.8
Total	**$ 640.4**	$ 1,481.0	$ 636.2

(1) Includes Canadian currency translation effects of $4.6 million, $(27.7) million and $15.0 million in 2009, 2008 and 2007, respectively.

We plan to drill approximately 136 gross wells (123.9 net) in 2010 compared with 143 gross wells (118.5 net) drilled in 2009. The number of net wells we plan to drill in 2010 is up slightly from 2009. This 2010 drilling

35

Table of Contents

Index to Financial Statements

program includes approximately $585 million in total capital and exploration expenditures, down from $640.4 million in 2009. This decline is primarily due to lower projected lease acquisition expenditures. 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 2010, 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 and increased lease acquisition costs in Pennsylvania. This change is currently estimated to be approximately 11% greater than 2009 levels. This increase will not have an impact on our cash flows.

Contractual Obligations

Our 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, 2009 are set forth in the following table:

		Payments Due by Year			
	Total	**2010**	**2011 to 2012**	**2013 to 2014**	**2015 & Beyond**
	(In thousands)				
Long-Term Debt[1]	**$ 805,000**	$	$ 218,000	$ 75,000	$ 512,000
Interest on Long-Term Debt[2]	**396,857**	52,280	87,914	76,949	179,714
Firm Gas Transportation Agreements[3]	**80,403**	10,977	21,599	6,746	41,081
Drilling Rig Commitments[3]	**6,364**	6,364			
Operating Leases[3]	**26,776**	5,845	10,029	8,443	2,459
Total Contractual Cash Obligations	**$ 1,315,400**	$ 75,466	$ 337,542	$ 167,138	$ 735,254

(1) At December 31, 2009, we had $143 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 $662 million long-term debt outstanding at December 31, 2009. Interest payments on our revolving credit facility were calculated by assuming that the December 31, 2009 outstanding balance of $143 million will be outstanding through the April 2012 maturity date. A constant interest rate of 3.9% was assumed, which was the 2009 weighted-average interest rate. Actual results will 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, 2009 was $29.7 million, up from $28.0 million at December 31, 2008, primarily due to $1.3 million of accretion expense during 2009 as well as $0.4 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.

Table of Contents

Index to Financial Statements

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. In 2009 we had a net downward revision of 200.1 Bcfe primarily due to (i) downward revisions of 101.6 Bcfe due to lower 2009 oil and natural gas prices compared to 2008 and (ii) downward revisions of 120.4 Bcfe due to the removal of proved undeveloped reserves scheduled for development beyond five years primarily due to the application of the SEC s new oil and gas reserve calculation methodology, partially offset by 21.9 Bcfe of positive performance revisions. In accordance with the new rules we priced proved oil and gas reserves using the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month within the 12-month period prior to the end of the reporting period. We did not record significant reserve revisions during 2008 and 2007. 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 $0.07 to $0.09 per Mcfe. Revisions in significant fields may individually affect our DD&A rate. It is estimated that a positive or negative reserve revision of 10% in one of our most productive fields would have a $(0.02) to $0.04 per Mcfe 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 Accounting Standards Codification (ASC) 360, Property, Plant, and Equipment. 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 field-by-field 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 assumptions management uses in its budgeting and forecasting process as well as 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 (16% at December 31, 2009) is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying natural gas and oil. In 2009, 2008 and 2007, 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.

Table of Contents

Index to Financial Statements

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 latter part of 2008 and during 2009, 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 $19.3 million or decrease by approximately $13.8 million, respectively per year.

In the past, based on the customary terms of the leases, the average leasehold life in the South region has been shorter than the average life in the North region. Average property lives in the North and South regions have been five and three years, respectively. 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 ASC 815. Under ASC 815, 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 ASC 815, 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 derivatives not qualifying as hedges, 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 ASC 820, Fair Value Measurements and Disclosures, that were required to be adopted (which excluded certain non financial assets and liabilities). Effective January 1, 2009, we applied all of the provisions of ASC 820, and this adoption did not have a material impact on any of our financial statements except for our impairment of oil and gas properties (see Note 2 of the Notes to the Consolidated Financial Statements). In the future, areas that could cause an impact would primarily be limited to asset impairments, including long-lived assets, asset retirement obligations and assets acquired and liabilities assumed in a business combination, if any. As defined in ASC 820, 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

Table of Contents

Index to Financial Statements

on the observability of those inputs. ASC 820 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, 2009, we had $114.7 million of financial assets, or 3% 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 2009, realized gains of $240.9 million were recognized in other comprehensive income. Derivative settlements during the year totaled $395.0 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. These estimates are compared to multiple quotes obtained from counterparties for reasonableness. 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. The resulting reduction to the net receivable derivative contract position was $0.2 million. 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 11 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 5.49% as of December 31, 2009, and the Citigroup Pension Liability Index, which was 5.96% as of December 31, 2009. 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, 2009 is reasonable.

In order to value our pension liabilities, we use the IRS 2009 Static 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, 2009, the assumed rate of increase was 10%. 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.

Table of Contents

Index to Financial Statements

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 2009, 2008 and 2007. 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 seven percent 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 prescribed under ASC 718 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 incorporates 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 7.1% 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 or operating cash flow metrics 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 5.2% 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, an aggregate of up to 100% of the fair market value of a share of our stock may be payable in common stock plus up to 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. An interpolated risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for one and two year bonds (as of the reporting date) set equal to the remaining duration of the performance period. Volatility was set equal to the annualized daily volatility for the remaining duration of the reporting 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 52% to approximately 86% for us and our peer group. The expected dividend is calculated using our annual dividends paid ($0.12 per share for 2009) divided by the December 31, 2009 closing price of our stock ($43.59). Based on these inputs discussed above, a ranking was projected identifying our rank relative to the peer group for each award period. 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

Table of Contents

Index to Financial Statements

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 ASC 718. The total expense for 2009 and 2008 was $1.2 million and $15.9 million, respectively, and is included in General and Administrative Expense in the Consolidated Statement of Operations. For further information regarding the supplemental employee incentive plans and our other stock-based compensation awards, please refer to Note 9 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. In addition, we are required to maintain an asset coverage ratio of the present value of proved reserves plus working capital to debt of 1.5 to 1.0 and a current ratio of 1.0 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, 2009, 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.

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 ASC 360, Property, Plant, and Equipment. 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 related commodity index falls, 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

Table of Contents

Index to Financial Statements

risk on all or a portion of our anticipated production 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.

Settlement of Dispute. In December 2008, we settled a dispute with a third party and as a result recorded a gain of $51.9 million (approximately $32.5 million after-tax). The dispute involved the propriety of possession of our intellectual property by a third party. The settlement was comprised of $20.2 million in cash paid by the third party to us and $31.7 million related to the fair value of unproved property rights transferred by the third party to us. The fair market value of the unproved property rights was determined based on observable market costs and conditions over a recent time period. Values were pro-rated by property based on the primary term remaining on the properties.

Recently Adopted Accounting Standards

In July 2009, the Financial Accounting Standards Board (FASB) issued ASC 105, Generally Accepted Accounting Principles, establishing the accounting standards codification and the hierarchy of generally accepted accounting principles (GAAP) as the sole source of authoritative non-governmental U.S. GAAP. The Codification was not intended to change U.S. GAAP; however, references to various accounting pronouncements and literature will now differ from what was previously being used in practice. Authoritative literature is now referenced by topic rather than by type of standard. As of July 1, 2009, the FASB no longer issues Statements, Interpretations, Staff Positions or EITF Abstracts. The FASB now communicates new accounting standards by issuing an Accounting Standards Update (ASU). All guidance in the Codification has an equal level of authority. ASC 105 is effective for financial statements that cover interim and annual periods ending after September 15, 2009, and supersedes all accounting standards in U.S. GAAP, aside from those issued by the SEC. There was no impact on our financial position, results of operations or cash flows as a result of the Codification.

In February 2008, the FASB issued an amendment to ASC 820, Fair Value Measurements and Disclosures, 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 measured on a nonrecurring basis to comply with ASC 820. Effective January 1, 2009, we applied these amendments of ASC 820 discussed above and there was no material impact on our financial statements except for our impairment of oil and gas properties. For further information, please refer to Note 2 and Note 11 of the Notes to the Consolidated Financial Statements.

Effective January 1, 2009, we adopted amendments that the FASB made to ASC 260, Earnings Per Share, regarding determining whether instruments granted in share-based payment transactions are participating securities. The adoption of these amendments did not have a material impact on our financial statements. For further information, please refer to Note 12 of the Notes to the Consolidated Financial Statements.

In March 2008, the FASB amended the disclosure requirements prescribed in ASC 815, Derivatives and Hedging. We adopted these amendments as of January 1, 2009. The principal impact was to require the expansion of our disclosure regarding our derivative instruments. For further information, please refer to Derivative Instruments and Hedging Activity in Note 11 of the Notes to the Consolidated Financial Statements.

In April 2009, the FASB amended guidance in ASC 820 regarding determining fair value when the volume and level of activity for an asset or liability has significantly decreased and identifying transactions that are not orderly. If an entity determines that either the volume or level of activity for an asset or liability has significantly decreased from normal conditions, or that price quotations or observable inputs are not associated with orderly transactions, increased analysis and management judgment will be required to estimate fair value. The objective in fair value measurement remains unchanged from what is prescribed in ASC 820 and should be reflective of the current exit price. Disclosures in interim and annual periods must include inputs and valuation techniques used to measure fair value, along with any changes in valuation techniques and related inputs during the period. In

Table of Contents

Index to Financial Statements

addition, disclosures for debt and equity securities must be provided on a more disaggregated basis. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB amended ASC 825, Financial Instruments, to require disclosures about fair value of financial instruments for publicly traded companies for both interim and annual periods. Historically, these disclosures were only required annually. The interim disclosures are intended to provide financial statement users with more timely and transparent information about the effects of current market conditions on an entity s financial instruments that are not otherwise reported at fair value. These amendments became effective for interim reporting periods ending after June 15, 2009. Comparative disclosures are only required for periods ending after the initial adoption. There was no material impact on our financial position, results of operations or cash flows as a result of the adoption. For further information, please refer to Note 11 of the Notes to the Consolidated Financial Statements.

In April 2009, the FASB amended the other-than-temporary impairment guidance for debt securities in ASC 320, Investments Debt and Equity Securities, to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. There were no amendments made to the recognition and measurement guidance for equity securities, but a new method of recognizing and reporting for debt securities was established. Disclosure requirements for impaired debt and equity securities have been expanded significantly and are now required quarterly, as well as annually. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on our financial position, results of operations or cash flows. Comparative disclosures are only required for periods ending after the initial adoption.

In June 2009, the FASB amended ASC 855, Subsequent Events, to require entities to disclose the date through which they have evaluated subsequent events and whether the date corresponds with the release of their financial statements. In addition, a new concept of financial statements being available to be issued was introduced. These amendments became effective for interim and annual periods ending after June 15, 2009 and did not have any impact on our financial position, results of operations or cash flows.

In August 2009, the FASB issued ASU No. 2009-05, Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value, which provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. ASU No. 2009-05 specifies that in cases where a quoted price in an active market is not available, a valuation technique should be applied that uses either the quote of the liability when traded as an asset, the quoted prices for similar liabilities or similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. Valuation methods discussed include using an income approach, such as a present value technique, or a market approach based on the amount at the measurement date that the reporting entity would pay to transfer the identical liability or would receive to enter into the identical liability. Entities are not required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents the transfer of the liability. ASU No. 2009-05 is codified in ASC 820-10 and is effective for the first reporting period (including interim periods) beginning after issuance. There was no impact on our financial position, results of operations or cash flows as a result of the adoption of ASU No. 2009-05. For further information, please refer to Note 11 of the Notes to the Consolidated Financial Statements.

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 has been phased out. Release No. 33-8995 is intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 are 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

Table of Contents

Index to Financial Statements

prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning January 1, 2010. The adoption of Release No. 33-8995 resulted in a downward revision to our proved reserves. For further information, please refer to the Supplemental Oil and Gas Information in the Notes to the Consolidated Financial Statements.

In January 2010, the FASB issued ASU No. 2010-03, Oil and Gas Reserve Estimation and Disclosures, in order to align the oil and gas reserve estimation and disclosure requirements of Extractive Activities Oil and Gas (Topic 932) with the requirements in the SEC s final rule, Modernization of the Oil and Gas Reporting Requirements issued in December 2008. The amendments to Topic 932 are effective for annual reporting periods ending on or after December 31, 2009.

In December 2008, the FASB issued an amendment to ASC 715-20, Compensation Retirement Benefits Defined Benefit Plans General, which requires enhanced disclosures regarding company benefit plans. Disclosure regarding plan assets should include discussion about how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure plan assets and significant concentrations of risk within plan assets. These amendments to ASC 715-20 are effective for fiscal years ending after December 15, 2009, and earlier application is permitted. Prior year periods presented for comparative purposes are not required to comply. These amendments to ASC 715-20 did not have a material impact on our financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

In January 2010, the FASB issued ASU No. 2010-06, Improving Disclosures about Fair Value Measurements, which amends ASC 820-10-50 to require new disclosures concerning (1) transfers into and out of Levels 1 and 2 of the fair value measurement hierarchy, and (2) activity in Level 3 measurements. In addition, ASU No. 2010-06 clarifies certain existing disclosure requirements regarding the level of disaggregation and inputs and valuation techniques. Finally, ASU No. 2010-06 makes conforming amendments to the guidance on employers disclosures about postretirement benefit plans assets (FASB ASC 715-20-50). ASU No. 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Early adoption is allowed. We are currently evaluating the impact ASU No. 2010-06 may have on our financial position, results of operations or cash flows.

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-lool 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.

Table of Contents

Index to Financial Statements

RESULTS OF OPERATIONS

2009 and 2008 Compared

We reported net income for 2009 of $148.3 million, or $1.43 per share. During 2008, we reported net income of $211.3 million, or $2.10 per share. Net income decreased in 2009 by $63.0 million, primarily due to a decrease in operating revenues, an increase in depreciation, depletion and amortization, an increase in interest expense, an increase in exploration expense and an increase in direct operations. Also impacting net income in 2008 was a gain on the settlement of a dispute. These decreases and increases were partially offset by decreased operating and income tax expenses, decreased brokered natural gas cost, decreased impairments of oil and gas properties and other assets, decreased impairments of unproved properties, decreased general and administrative expense and loss on sale of assets. Operating revenues decreased by $66.5 million largely due to decreases in brokered natural gas and natural gas production revenues. Operating expenses decreased by $33.1 million between periods due primarily to decreases in impairments of unproved properties and oil and gas properties, brokered natural gas costs, taxes other than income and general and administrative expenses, partially offset by increased depreciation, depletion and amortization, exploration expense and direct operations. In addition, net income was impacted in 2009 by higher interest expense, decreased income tax expense and, to a lesser extent, loss on sale of assets. Income tax expense was lower in 2009 as a result of a decrease in operating income, as discussed above, and a decrease in the effective tax rate. The decrease in the effective tax rate is primarily due to an overall reduction in state deferred tax liabilities and tax benefits associated with foreign tax credits.

Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $7.47 per Mcf for 2009 compared to $8.39 per Mcf for 2008. These prices include the realized impact of derivative instrument settlements, which increased the price by $3.80 per Mcf in 2009 and by $0.20 per Mcf in 2008. The following table excludes the unrealized loss from the change in fair value of our basis swaps of $2.0 million for the year ended December 31, 2009, which has been included within Natural Gas Production Revenues in the Consolidated Statement of Operations. There was no revenue impact from the unrealized change in natural gas derivative fair value for the year ended December 31, 2008.

	Year Ended December 31,		Variance	
	2009	**2008**	**Amount**	**Percent**
Natural Gas Production *(Mmcf)*				
North	**48,154**	39,715	8,439	21%
South	**48,802**	46,568	2,234	5%
Canada	**958**	4,142	(3,184)	(77%)
Total Company	**97,914**	90,425	7,489	8%
Natural Gas Production Sales Price *($/Mcf)*				
North	**$ 6.59**	$ 7.95	$ (1.36)	(17%)
South	**$ 8.42**	$ 8.84	$ (0.42)	(5%)
Canada	**$ 3.72**	$ 7.62	$ (3.90)	(51%)
Total Company	**$ 7.47**	$ 8.39	$ (0.92)	(11%)
Natural Gas Production Revenue *(In thousands)*				
North	**$ 317,456**	$ 315,582	$ 1,874	1%
South	**410,674**	411,616	(942)	0%
Canada	**3,558**	31,557		