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

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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.

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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

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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

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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

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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.

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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.

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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.

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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.

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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	

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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