CABOT OIL & GAS CORP
Form 10-K
February 27, 2009

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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, 2008

Commission file number 1-10447

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

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

1200 Enclave Parkway, Houston, Texas 77077

(Address of principal executive offices including ZIP code)

(281) 589-4600

(Registrant s telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $.10 per share	**New York Stock Exchange**
Rights to Purchase Preferred Stock	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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 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 x.

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, 2008) was approximately $7.0 billion.

As of February 19, 2009, there were 103,447,221 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held April 28, 2009 are incorporated by reference into Part III of this report.

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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, 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. Our four principal areas of operation are the Appalachian Basin, onshore Gulf Coast, including south and east Texas and north Louisiana, the Rocky Mountains and the Anadarko Basin. We also operate in the deep gas basin of Western Canada. Operationally, we have four regional offices located in Houston, Texas; Charleston, West Virginia; Denver, Colorado; and Calgary, Alberta.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

EAST REGION

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

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

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

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

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

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

Ancillary to our exploration, development and production operations, we operated a number of gas gathering and transmission pipeline systems, made up of approximately 3,200 miles of pipeline with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2008. The majority of our pipeline infrastructure in West Virginia is regulated by the Federal Energy Regulatory Commission (FERC) for interstate transportation service and the West Virginia Public Service Commission (WVPSC) for intrastate transportation service. As such, the transportation rates and terms of service of our pipeline subsidiary, Cranberry Pipeline Corporation, are subject to the rules and regulations of the FERC and the WVPSC. Our natural gas gathering and transmission pipeline systems enable us to connect new wells quickly and to transport natural gas from the wellhead directly to interstate pipelines, local distribution companies and industrial end users. Control of our gathering and transmission pipeline systems also enables us to purchase, transport and sell natural gas produced by third parties. In addition, we can engage in development drilling without relying upon third parties to transport our natural gas and incur only the incremental costs of pipeline and compressor additions to our system.

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

The principal markets for our East region natural gas are in the northeast United States. We sell natural gas to industrial customers, local distribution companies and gas marketers both on and off our pipeline and gathering system.

Approximately 70% of our natural gas sales volume in the East region is sold at index-based prices under contracts with a term of one year or greater. In addition, spot market sales are made at index-based prices under month-to-month contracts, while industrial and utility sales generally are made under year-to-year contracts. Approximately one percent of East production is sold on fixed price contracts that typically renew annually.

GULF COAST REGION

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

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

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million for capital and exploration expenditures in the region. Our 2009 Gulf Coast drilling program will emphasize activity primarily in east Texas.

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

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

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

Our principal markets for Gulf Coast region natural gas are in the industrialized Gulf Coast area and the northeast United States. We sell natural gas to intrastate pipelines, natural gas processors and marketing companies. Currently, approximately 70% of our natural gas sales volumes in the Gulf Coast region are sold at index-based prices under contracts with terms of one year or greater. The remaining 30% of our sales volumes are sold at index-based prices under short-term agreements. The Gulf Coast properties are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

In 2008, we produced and marketed approximately 1,598 barrels of crude oil/condensate/NGL per day in the Gulf Coast region at market responsive prices.

WEST REGION

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

Our principal markets for West region natural gas are in the northwest and midwest United States. We sell natural gas to power generators, natural gas processors, local distribution companies, industrial customers and marketing companies. Currently, approximately 90% of our natural gas production in the West region is sold primarily under contracts with a term of one to three years at index-based prices. Another nine percent of the natural gas production is sold under short-term arrangements at index-based prices, and the remaining one percent is sold under certain fixed-price contracts. The West region properties are connected to the majority of the midwest and northwest interstate and intrastate pipelines, affording us access to multiple markets.

In 2008, we produced and marketed approximately 451 barrels of crude oil/condensate/NGL per day in the West region at market responsive prices.

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Rocky Mountains

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

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

We had 716 wells (329.4 net) in the Rocky Mountains area as of December 31, 2008, of which 372 wells are operated by us. Principal producing intervals in the Rocky Mountains area are in the Almond, Frontier, Dakota and Honaker Trail formations at depths ranging from 4,200 to 14,375 feet, with an average depth of approximately 10,900 feet. Average net daily production in the Rocky Mountains during 2008 was 41.3 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2008 was 14.5 Bcf and 95 Mbbls, respectively.

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

Mid-Continent

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

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

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

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

CANADA REGION

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

Capital and exploration expenditures in Canada were $25.4 million for 2008, or two percent of our total 2008 capital and exploration expenditures, compared to $55.1 million for 2007, or nine percent of our total 2007

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capital and exploration expenditures. For 2009, we have budgeted approximately $1 million for capital and exploration expenditures in the area.

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

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

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

In 2008, we produced and marketed approximately 59 barrels of crude oil/condensate per day in the Canada region at market responsive prices.

RISK MANAGEMENT

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production in all of our regions. While there are many different types of derivatives available, in 2008 we employed natural gas and crude oil price collar and swap agreements for portions of our 2008 through 2010 production to attempt to manage price risk more effectively. In 2007 and 2006, we primarily employed price collars to hedge our price exposure on our production. The collar arrangements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price falls below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas for the period is greater or less than the fixed price established for that period when the swap is put in place.

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

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

We will continue to evaluate the benefit of employing derivatives in the future. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations and Quantitative and Qualitative Disclosures about Market Risk for further discussion concerning our use of derivatives.

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RESERVES

Current Reserves

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

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

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

(2) Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil, condensate or natural gas liquids.

The proved reserve estimates presented here were prepared by our petroleum engineering staff and reviewed by Miller and Lents, Ltd., independent petroleum engineers. Miller and Lents concluded the following: In their judgment we have an effective system for gathering data and documenting information required to estimate our proved reserves and project our future revenues; we used appropriate engineering, geologic and evaluation principles and techniques in accordance with practices generally accepted in the petroleum industry in making our estimates and projections and our total proved reserves are reasonable. For additional information regarding estimates of proved reserves, the review of such estimates by Miller and Lents, Ltd., and other information about our oil and gas reserves, see the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8. A copy of the review letter by Miller and Lents, Ltd. has been filed as an exhibit to this Form 10-K. Our estimates of proved reserves in the table above are consistent with those filed by us with other federal agencies. During 2008, we filed estimates of our oil and gas reserves for the year 2007 with the Department of Energy. These estimates differ by five percent or less from the reserve data presented. Our reserves are sensitive to natural gas and crude oil sales prices and their effect on economic producing rates. Our reserves are based on oil and gas index prices in effect on the last day of December 2008.

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

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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, 2005	1,262,096	11,463	1,330,874
Revision of Prior Estimates[2]	(17,675)	673	(13,640)
Extensions, Discoveries and Other Additions	246,197	1,066	252,594