CABOT OIL & GAS CORP
Form 10-K
February 28, 2012

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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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, 2011

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 ý No o

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 o No ý

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 ý No o

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 ý No o

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 ý.

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 ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

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, 2011) was approximately $6.9 billion.

As of February 17, 2012, there were 209,826,622 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held May 1, 2012 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 also intended to identify forward-looking statements. These statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including geographic basis differentials) of natural gas and oil, results of future drilling and marketing activity, future production and costs, legislative and regulatory initiatives, electronic, cyber or physical security breaches 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.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and included within this Annual Report on Form 10-K:

Abbreviations

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet of natural gas equivalent.

Mbbls. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent.

Mmbtu. One million British thermal units.

Mmcf. One million cubic feet of natural gas.

Mmcfe. One million cubic feet of natural gas equivalent.

NGL. Natural gas liquids.

NYMEX. New York Mercantile Exchange.

Definitions

Developed reserves. Developed reserves are reserves that can be expected to be recovered: (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential. An adjustment to the price of oil or gas from an established spot market price to reflect differences in the quality and/or location of oil or gas.

Dry Hole. Exploratory or development well that does not produce oil or gas in commercial quantities.

Exploitation activities. The process of the recovery of fluids from reservoirs and drilling and development of oil and gas properties.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, or a service well.

Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geological barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms *structural feature* and *stratigraphic condition* are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

Oil. Crude oil and condensate.

Operator. The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities, which become part of the cost of oil and gas produced.

Proved properties. Properties with proved reserves.

Proved reserves. Proved reserves are those quantities, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions and operating methods prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Recompletion. An operation whereby a completion in one zone is abandoned in order to attempt a completion in a different zone within the existing wellbore.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering

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oil and gas or related substances to market, and all permits and financing required to implement the project.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Royalty interest. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Service well. A well drilled or completed for the purpose of supporting production in a existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

Standardized measure. The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of future price changes to the extent provided by contractual arrangements in existence at year-end), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the appropriate year-end statutory federal and state income tax rate with consideration of future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved oil and gas reserves.

Undeveloped reserves. Undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Unproved properties. Properties with no proved reserves.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

PART I

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Cabot Oil & Gas Corporation is an independent oil and gas company engaged in the development, exploitation and exploration of oil and gas properties. Our primary areas of operation include Appalachia, east and south Texas, and Oklahoma. Our assets are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs. We operate in one segment, natural gas and oil development, exploitation and exploration, exclusively in the continental United States. We have regional offices located in Houston, Texas and Pittsburgh, Pennsylvania.

OVERVIEW

On an equivalent basis, our production in 2011 increased by 44% from 2010. We produced 187.5 Bcfe, or 513.7 Mmcfe per day, in 2011, as compared to 130.6 Bcfe, or 357.9 Mmcfe per day, in 2010. Natural gas production increased by 53.4 Bcf, or 43%, to 178.8 Bcf in 2011 from 125.5 Bcf in 2010, primarily due to increased production in the Marcellus shale associated with our increased drilling program and upgrades to the Lathrop compressor station in Susquehanna County, Pennsylvania, which included the commissioning of new compression during 2011. Partially offsetting the production increase in northeast Pennsylvania were decreases in production primarily in east and south Texas due to normal production declines, the sale of oil and gas properties in Colorado, Utah and Wyoming and a shift from gas to oil projects. Crude oil/condensate/NGL production increased by 584 Mbbls, or 68%, from 859 Mbbls in 2010 to 1,443 Mbbls in 2011 primarily due to an increase in production resulting from our Eagle Ford oil shale drilling program in south Texas.

Our average realized natural gas price for 2011 was $4.46 per Mcf, 22% lower than the $5.69 per Mcf price realized in 2010. Our average realized crude oil price for 2011 was $90.49 per Bbl, 8% lower than the $97.91 per Bbl price realized in 2010. These realized prices include realized gains and losses resulting from commodity derivatives. For information about the impact of these derivatives on realized prices, refer to "Results of Operations" in Item 7.

Our proved reserves totaled approximately 3,033 Bcfe at December 31, 2011, of which 96% were natural gas. This reserve level was up by 12% from 2,701 Bcfe at December 31, 2010 on the strength of results from our drilling program. In 2011, we had a net upward revision of 21.6 Bcfe, which was primarily due to an upward performance revision of 214.9 Bcfe, primarily in the Dimock field in northeast Pennsylvania, partially offset by a downward revision of 189.8 Bcfe of proved undeveloped reserves that are no longer in our five-year development plan and a downward revision of 3.6 Bcfe associated with decreased reserve commodity pricing. For information about other changes in our proved reserves, refer to the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8.

For the year ended December 31, 2011, we drilled 161 gross wells (96.0 net) with a success rate of over 99% compared to 113 gross wells (87.1 net) with a success rate of 98% for the prior year. In 2012, we plan to drill approximately 120 to 130 gross wells, focusing our capital program in the Marcellus shale in northeast Pennsylvania, the Eagle Ford oil shale in south Texas and the Marmaton oil play in Oklahoma.

Our 2011 total capital and exploration spending was $905.5 million compared to $891.5 million in 2010. This increase in spending was substantially driven by an expanded Marcellus shale horizontal drilling program and increases in our drilling programs in the Eagle Ford oil shale in south Texas and the Marmaton oil play in Oklahoma. In both 2011 and 2010, we allocated our planned program for capital and exploration expenditures among our various operating areas based on return expectations, availability of services and human resources. We plan to continue such method of allocation in 2012.

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Funding of the program is expected to be provided by operating cash flow, existing cash and, if required, borrowings under our credit facility. In 2012, we plan to spend between $750 and $790 million on capital and exploration activities.

While we consider acquisitions from time to time, we remain focused on pursuing 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 in the current commodity pricing environment and will continue to add shareholder value over the long-term.

DIVESTITURES

In October 2011, we sold certain proved oil and gas properties located in Colorado, Utah and Wyoming to Breitburn Energy Partners, L.P. for $285.0 million. We received $283.2 million in cash proceeds, after closing adjustments, and recognized a $4.2 million gain on sale of assets.

In May 2011, we sold certain of our unproved Haynesville and Bossier Shale oil and gas properties in east Texas to a third party. We received approximately $47.0 million in cash proceeds and recognized a $34.2 million gain on sale of assets.

In 2011, we sold various other unproved properties and other assets for total proceeds of $73.5 million and recognized an aggregate gain of $25.0 million.

In December 2010, we sold our existing Pennsylvania gathering infrastructure of approximately 75 miles of pipeline and two compressor stations to Williams Field Services (Williams), a subsidiary of Williams Partners L.P., for $150 million. Under the terms of the purchase and sale agreement, we were obligated to construct pipelines to connect certain of our 2010 program wells, complete the construction of the Lathrop compressor station and complete taps into certain pipeline delivery points. These obligations were completed in 2011. As of December 31, 2010, we recognized a $49.3 million gain on sale of assets, which included the accrual of $17.9 million associated with the obligations described above. We also entered into a 25-year firm gathering contract with Williams that requires Williams to complete construction of approximately 32 miles of high pressure pipeline, 65 miles of trunklines and two compressor stations in Susquehanna County, Pennsylvania in 2011 and 2012. Additionally, Williams will connect all of our drilling program wells, which will connect our production to five interstate pipeline delivery options.

In 2010, we sold various other proved and unproved properties and other assets for total proceeds of $32.2 million and recognized an aggregate gain of $16.3 million.

In April 2009, we sold substantially all of our Canadian proved oil and gas properties to Tourmaline Oil Corporation (Tourmaline) in exchange for cash and common shares of Tourmaline. In November 2010, we sold our investment in Tourmaline for $61.3 million and recognized a $40.7 million gain on sale of assets.

DESCRIPTION OF PROPERTIES

Our properties are primarily located in Appalachia, east and south Texas and Oklahoma. Our activities in Appalachia are concentrated primarily in northeast Pennsylvania and in West Virginia. There are multiple producing intervals in Appalachia that includes the Devonian (including Marcellus), Big Lime, Weir and Berea shale formations at depths primarily ranging from approximately 950 to 7,800 feet, with an average depth of approximately 4,375 feet. Principal producing intervals in east Texas are in the Cotton Valley, Haynesville, Bossier, and James Lime formations and the principal producing intervals in south Texas are in the Eagle Ford, Frio, Vicksburg and Wilcox formations, with total depths ranging from approximately 2,650 to 19,650 feet, with an average depth of approximately

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11,150 feet. Our activities in Oklahoma include the Marmaton, Chase, Morrow and Chester formations in the Anadarko Basin at depths ranging from approximately 2,350 to 18,630 feet, with an average depth of approximately 10,490 feet. We also hold undeveloped acreage in the Rocky Mountains, located in Montana and Nevada.

Ancillary to our exploration, development and production operations, we operate a number of gas gathering and transmission pipeline systems, made up of approximately 3,105 miles of pipeline with interconnects to three interstate transmission systems and five local distribution companies and numerous end users as of the end of 2011. The majority of our pipeline infrastructure is located in West Virginia and 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 in West Virginia 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 also 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 typically associated with winter natural gas sales, while maintaining production at a nearly constant rate throughout the year. The pipeline systems and storage fields are fully integrated with our operations.

MARKETING

The principal markets for our natural gas are in the northeastern and midwestern United States and the industrialized Gulf Coast area. In the northeastern United States, we sell natural gas to industrial customers, local distribution companies and gas marketers both on and off our pipeline and gathering system. In the Gulf Coast area and the midwestern United States, we sell natural gas to intrastate pipelines, natural gas processors and marketing companies. Properties in the Gulf Coast area are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

Approximately 35-40% of our natural gas sales volume in 2011 was sold at index-based prices under contracts with terms of one year or greater. Our remaining natural gas sales volume was sold under contracts with terms less than one year. 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.

In 2011, we produced and marketed approximately 490.0 Mmcf per day of natural gas and 4.0 Mbbls of crude oil/condensate/NGL per day at market responsive prices. Average daily production in 2011 was 513.7 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2011 was 178.8 Bcf and 1,443 Mbbls, respectively.

In February 2012, we entered into a Precedent Agreement with Constitution Pipeline Company, LLC, a wholly owned subsidiary of Williams Partners L.P., to develop and construct a large diameter pipeline to transport our production in northeast Pennsylvania to both the New England and New York markets. Under the terms of the agreement, we will own 500,000 Mcf per day of capacity on the newly constructed pipeline and acquire a 25% equity interest in the project, subject to certain terms and conditions yet to be determined and regulatory approval.

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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. While there are many different types of derivatives available, we utilized natural gas and crude oil swap agreements and crude oil collar agreements for portions of our 2011 production to attempt to manage price risk more effectively. During 2011, we also entered into crude oil swaps to hedge our price exposure on our 2012 production, natural gas swaps to hedge our price exposure on our 2011 and 2012 production and natural gas collars to hedge our price exposure on our 2013 production. In addition, we also have natural gas basis swaps covering a portion of anticipated 2012 production, which do not qualify for hedge accounting. In 2010 and 2009, we utilized 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 2011, swaps covered 42% of natural gas production and 20% of crude oil production at a weighted-average price of $5.30 per Mcf and $106.20 per Bbl, respectively, and collars covered 26% of crude oil production at a weighted-average price of $90.88 per Bbl.

As of December 31, 2011, we had the following outstanding commodity derivatives:

Commodity and Derivative Type	Weighted-Average Contract Price	Volume	Contract Period
Derivatives Designated as Hedging			
Natural Gas Swaps	$5.22 per Mcf	95,998 Mmcf	Jan. 2012 - Dec. 2012
Natural Gas Collars	$6.20 Ceiling/ $5.15 Floor per Mcf	17,729 Mmcf	Jan. 2013 - Dec. 2013
Crude Oil Swaps	$98.28 per Bbl	732 Mbbl	Jan. 2012 - Dec. 2012
Derivatives Not Designated as Hedging Instruments			
Natural Gas Basis Swaps	$(0.27) per Mcf	17,042 Mmcf	Jan. 2012 - Dec. 2012

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

Our reserve estimates were based on decline curve extrapolations, material balance calculations, volumetric calculations, analogies, or combinations of these methods for each well, reservoir or field. The proved reserve estimates presented herein were prepared by our petroleum engineering staff and audited 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. Further, Miller and Lents has concluded (1) the reserves estimation methods employed by us were appropriate, and our classification of such reserves was appropriate to the relevant SEC reserve definitions, (2) our reserves estimation processes were comprehensive and of sufficient depth, (3) the data upon which we relied were adequate and of sufficient quality, and (4) the results of our estimates and projections are, in the aggregate, reasonable. For additional information regarding estimates of proved reserves, the audit of such estimates by Miller

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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 audit letter by Miller and Lents, Ltd., dated January 31, 2012, 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 2011, 2010 and 2009, respectively. 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 Vice President of Engineering and Technology, who maintains oversight and compliance responsibility for the internal reserve estimation process and provides oversight for the annual audit of our year-end reserves by our independent third party engineers, Miller and Lents, Ltd. Our corporate reservoir engineering group consists of four petroleum/chemical engineers, with petroleum/chemical engineering degrees and between one and 29 years of industry experience, between one and 29 years of reservoir engineering/management experience, and between one and 13 years managing our reserves. All four engineers are members of the Society of Petroleum Engineers.

Qualifications of Third Party Engineers

The technical person primarily responsible for the audit 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, 2011 we had 1,233.1 Bcfe of proved undeveloped reserves, which represents an increase of 256.2 Bcfe compared with December 31, 2010. For 2011, total capital related to the development of proved undeveloped reserves was $284.5 million, resulting in the conversion of 228.7 Bcfe of reserves to proved developed. During 2011, we had 556.3 Bcfe of proved undeveloped reserve additions and 161.7 Bcfe of positive proved undeveloped reserve performance revisions, primarily in the Dimock field in northeast Pennsylvania. These increases were partially offset by sales of proved undeveloped reserves of 43.3 Bcfe located in Colorado, Utah, Wyoming and east Texas and the removal of 189.8 Bcfe of proved undeveloped reserves associated with drilling locations, primarily in east Texas, West Virginia and Oklahoma, no longer anticipated to be developed within the next five years primarily due to a continued shift in our drilling program.

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Historical Reserves

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

	As of December 31,		
	2011	**2010**	**2009**
Natural Gas *(Mmcf)*			
Proved Developed Reserves	**1,734,088**	1,681,451	1,288,169
Proved Undeveloped Reserves	**1,175,828**	962,707	724,993
	2,909,916	2,644,158	2,013,162
Crude Oil & Liquids *(Mbbl)*			
Proved Developed Reserves	**10,922**	7,129	6,082
Proved Undeveloped Reserves[1]	**9,548**	2,362	1,701
	20,470	9,491	7,783
Natural Gas Equivalent *(Mmcfe)*[2]	**3,032,735**	2,701,102	2,059,858
Reserve Life *(in years)*[3]	**16.2**	20.7	20.0

(1) *Proved undeveloped reserves for 2011 include 132.4 Bcfe of reserves drilled but awaiting completion.*

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

(3) *Reserve life index is equal to year-end reserves divided by annual production for the year ended December 31, 2011, 2010 and 2009, respectively.*

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Production, Sales Price and Production Costs

The following table presents historical information about our production volumes for natural gas and crude oil (including condensate and natural gas liquids), average natural gas and crude oil realized sales prices, and average production costs per equivalent, including our Dimock field located in northeast Pennsylvania, which contains more than 15% of our total proved reserves.

	Year Ended December 31,		
	2011	**2010**	**2009**
Production Volumes			
Natural Gas *(Bcf)*			
Dimock Field	**119.3**	49.5	36.3
Total	**178.8**	125.5	98.0
Crude Oil/Condensate/NGL *(Mbbl)*			
Dimock Field			
Total	**1,443**	859	845
Equivalents *(Bcfe)*			
Dimock Field	**119.3**	49.5	36.3
Total	**187.5**	130.7	103.0
Natural Gas Average Sales Price *($/Mcf)*[1]			
Dimock Field	**$ 3.85**	$ 4.48	$ 4.19
Total	**4.46**	5.69	7.61
Crude Oil Average Sales Price *($/Bbl)*[1]			
Dimock Field	**$**	$	$
Total	**90.49**	97.91	85.52
Average Production Costs *($/Mcfe)*			
Dimock Field	**$ 0.08**	$ 0.08	$ 0.03
Total	**0.47**	0.89	1.08

(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). Includes realized impact of derivative instruments.*

Acreage

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 10 years. These properties are held for longer periods if production is established.

The following table summarizes our gross and net developed and undeveloped leasehold and mineral fee acreage at December 31, 2011. 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	1,139,459	956,384	846,643	698,787	1,986,102	1,655,171
Mineral Fee Acreage	133,622	112,234	61,744	52,242	195,366	164,476
Total	**1,273,081**	**1,068,618**	**908,387**	**751,029**	**2,181,468**	**1,819,647**

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Total Net Undeveloped Acreage Expiration

Our net undeveloped acreage expiring over the next three years as of December 31, 2011 is 128,463, 197,514 and 51,518 for the years ending December 31, 2012, 2013 and 2014, respectively. These amounts assume no future successful development or renewal of undeveloped acreage.

Well Summary

The following table presents our ownership in productive natural gas and oil wells at December 31, 2011. This summary includes natural gas and oil wells in which we have a working interest.

	Gross	Net
Natural Gas	5,091	4,325.9
Crude Oil	226	176.1
Total[1][2]	**5,317**	**4,502.0**

(1) *Total excludes 55 (52.3 net) service wells.*

(2) *Total percentage of gross operated wells is 89.0%.*

Drilling Activity

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

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	**149**	**86.0**	96	74.3	124	103.6
Dry			1	1.0	5	4.0
Extension Wells						
Productive	**7**	**5.5**	12	8.3	7	7.0
Dry						
Exploratory Wells						
Productive	**4**	**3.5**	3	2.5	5	2.5
Dry	**1**	**1.0**	1	1.0	2	1.5
Total	**161**	**96.0**	113	87.1	143	118.6
Wells Acquired					1	1.0

At December 31, 2011, 12 wells (7.6 net) were being drilled or awaiting completion.

OTHER BUSINESS MATTERS

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 Appalachia area our extensive acreage position, existing natural gas gathering and pipeline systems in West Virginia and our access to gathering and pipeline infrastructure in Pennsylvania, along with services and equipment that we have secured for the upcoming years and storage fields in West Virginia, enhance our competitive position over other producers who do not have similar systems or

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services in place. We also actively compete against other companies with substantially larger financial and other resources.

Major Customer

In 2011, we did not have any one customer account for more than 10% of our total sales. In 2010, one customer accounted for approximately 11% of our total sales. In 2009, two customers accounted for approximately 13% and 11%, respectively, of our total sales. We do not believe that the loss of any of these customers would have a material adverse effect on us because alternative customers are readily available.

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

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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. In 2010, the FERC issued Penalty Guidelines for the determination of civil penalties in an effort to add greater fairness, consistency and transparency to its enforcement program.

Our natural gas sales prices nevertheless continue to be affected by intrastate and interstate gas transportation regulation, because the prices we receive for our production are affected by the cost of transporting the gas to the consuming market. Through a series of comprehensive rulemakings, beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, the FERC has adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes were intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of gas to the primary role of gas transporters, and by increasing the transparency of pricing for pipeline services. The FERC has also established regulations governing the relationship of pipelines with their marketing affiliates, which essentially require that designated employees function independently of each other, and that certain information not be shared. The FERC has also implemented standards relating to the use of electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis.

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

Certain of our pipeline systems and storage fields in West Virginia are regulated for safety compliance by the U.S. Department of Transportation (DOT) and the West Virginia Public Service Commission. In 2002, Congress enacted the Pipeline Safety Improvement Act of 2002 (2002 Act), which contains a number of provisions intended to increase pipeline operating safety. The DOT's final regulations implementing the act became effective February 2004. Among other provisions, the regulations require that pipeline operators implement a pipeline integrity management program that must at a minimum include an inspection of gas transmission and non-rural gathering pipeline facilities in certain locations within 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. The initial baseline assessments under our integrity management program for our pipeline system in West Virginia are 96% complete and are expected to be fully complete by the December 2012 deadline. Clarification from the DOT published in 2009 brought to light the need for further baseline assessments of cased pipeline crossings covered under our integrity management program. Reassessment of our West Virginia pipeline system is scheduled to start in 2013 based on the 7 year reassessment requirement.

In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act), 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

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pipeline security plans and critical facility inspections. Pursuant to the PIPES Act, the DOT issued regulations on May 5, 2011 that would, with limited exceptions, subject all low-stress hazardous liquids pipelines, regardless of location or size, to the DOT's pipeline safety regulations.

In December 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The act increases the maximum civil penalties for pipeline safety administrative enforcement actions; requires the DOT to study and report on the expansion of integrity management requirements, the sufficiency of existing gathering line regulations to ensure safety, and the use of leak detection systems by hazardous liquid pipelines; requires pipeline operators to verify their records on maximum allowable operating pressure; and imposes new emergency response and incident notification requirements.

On December 3, 2009, the 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, 2013. The DOT expedited the program implementation deadline to October 1, 2011 for most of the requirements, except for certain provisions regarding adequate information and alarm management, which have a program implementation deadline of August 1, 2012. Effective January 1, 2011, natural gas and hazardous liquid pipelines became subject to updated reporting requirements with DOT. On August 25, 2011, the DOT issued an Advanced Notice of Proposed Rulemaking in which it explained that the DOT is considering changes to the pipeline safety regulations, including expanding its regulation of gas gathering lines.

We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. Similarly, it is impossible to predict what proposals, if any, that affect the oil and natural gas industry might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the recent trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas, cannot be predicted.

Federal Regulation of Petroleum

Our sales of oil and natural gas liquids are not regulated and are at market prices. The price received from the sale of these products is affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines. Effective January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In December 2010, 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 2.65 percent should be the oil pricing index for the five-year period beginning July 1, 2011. Another FERC matter that may impact our transportation costs relates to a 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

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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 stricter over time. Under these increasingly stringent requirements, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners and operators) or clean up property contamination (including groundwater contamination by prior owners or operators) or to perform plugging operations to prevent future contamination.

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

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as the "Superfund" law, and comparable state laws and regulations impose 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 current and past owners and operators of a site where the release occurred and any party that treated or disposed of or arranged for the treatment or disposal of hazardous substances found at a site. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources

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and for the costs of certain health studies. 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 addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. 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 joint and several strict 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 the Federal Clean Air Act and comparable local and state laws and regulations to control emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control toxic air pollutants might require installation of additional controls. 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. Most of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. Such efforts could have an adverse effect on oil and natural gas production activities. For additional information about hydraulic fracturing and related environmental matters, please read "Item 1A. Risk Factors Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays."

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Greenhouse Gas. In response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to global climate change, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases from sources within the United States between 2012 and 2050. In addition, almost one-half of the 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. The EPA has also begun to regulate carbon dioxide and other greenhouse gas emissions under existing provisions of the Clean Air Act. 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, 2011, we had 529 active employees. We recognize that our success is significantly influenced by the relationship we maintain with our employees. Overall, we believe that our relations with our employees are satisfactory. The Company and its employees are not represented by a collective bargaining agreement.

Website Access to Company Reports

We make available free of charge through our website, www.cabotog.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). Information on our website is not a part of this report. In addition, the SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements and other information filed by the Company. The public may read and copy materials that we file with the SEC at the SEC's Public Reference Room located at 100 F Street, NE, Washington, DC 20549. Information regarding the operation of the Public Reference Room can be obtained by calling the SEC at 1-800-SEC-0330.

Corporate Governance Matters

The Company's Corporate Governance Guidelines, Corporate Bylaws, Code of Business Conduct, Corporate Governance and Nominations Committee Charter, Compensation Committee Charter and Audit Committee Charter are available on the Company's website at www.cabotog.com, under the "Governance" section of "Investor Info." 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 decreased from an average price of $4.39 per Mmbtu in 2010 to an average price of $4.04 per Mmbtu in 2011. Natural gas prices were $3.36 per Mmbtu in December 2011 and have continued to decline to $2.68 per Mmbtu in February 2012. Natural gas prices represent the first of the month Henry Hub index price per Mmbtu. Oil prices have increased from an average price of $77.32 per barrel in 2010 to an average price of $94.01 per barrel in 2011. Depressed prices in the future would have a negative impact on our

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future financial results. Because our reserves are predominantly natural gas, changes in natural gas prices have a more significant impact on our financial results.

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

- the level of consumer product demand;
- weather conditions;
- political conditions in natural gas and oil producing regions, including the Middle East;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign imports;
- actions of governmental authorities;
- pipeline availability and capacity constraints;
- inventory storage levels;
- domestic and foreign governmental regulations;
- the price, availability and acceptance of alternative fuels; and
- overall economic conditions.

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

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

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

- unexpected drilling conditions, pressure or irregularities in formations;

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

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate for activity within a particular geographic area may decline. We may ultimately not be able to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may not be able to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location.

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Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

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

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

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

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

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

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on 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

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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 reserves as of December 31, 2011 will increase at an estimated rate of 6% during 2012 and then decline at estimated rates of 30%, 22% and 16% during 2013, 2014 and 2015, 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.

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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;
- pipe or cement failures and casing collapses, which can release natural gas, oil, drilling fluids or hydraulic fracturing fluids;
- uncontrolled flows of natural gas, oil or well fluids;
- fires;
- formations with abnormal pressures;
- handling and disposal of materials, including drilling fluids and hydraulic fracturing fluids;
- pollution and other environmental risks; and
- natural disasters.

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, suspension or 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, 2011, we owned or operated approximately 3,105 miles of natural gas gathering and pipeline systems. As part of our normal maintenance program, we have identified certain segments of our pipelines that we believe periodically require repair, replacement or additional maintenance.

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

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

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 11.0% of our total owned gross wells, or approximately 3.1% of our owned net wells, as of December 31, 2011. 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.

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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. We deliver our natural gas and oil production primarily through gathering systems and pipelines that we do not own. The lack of available of capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Third-party systems and facilities may be unavailable due to market conditions or mechanical or other reasons. 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. While there are many different types of derivatives available, we utilized natural gas and crude oil swap agreements and crude oil collar agreements for portions of our 2011 production to attempt to manage price risk more effectively. During 2011, we also entered into crude oil swaps to hedge our price exposure on our 2012 production, natural gas swaps to hedge our price exposure on our 2011 and 2012 production and natural gas collars to hedge our price exposure on our 2013 production. In addition, we also have 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

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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.

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

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. Most of our wells would not be economical without the use of

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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, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and is developing guidance documents related to this newly asserted regulatory authority. As a result, we may be subject to 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, legislation introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, and we voluntarily disclose on a well-by-well basis the chemicals we use in the hydraulic fracturing process at www.fracfocus.org.

In addition to these federal legislative proposals, some states in which we operate, such as Pennsylvania, West Virginia, Texas, Kansas, Louisiana and Montana, and certain local governments have adopted, and others are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, 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. For example, the Railroad Commission of Texas adopted rules in December 2011 requiring disclosure of certain information regarding the components used in the hydraulic fracturing process. In addition, both the State of Pennsylvania and certain local governments in that state have adopted a variety of regulations limiting how and where fracturing can be performed. Moreover, in April 2011, the Pennsylvania Department of Environmental Protection (PaDEP) called on all Marcellus Shale natural gas drilling operators to voluntarily cease by May 19, 2011 delivering wastewater to those centralized treatment facilities that were grandfathered from the application of last year's Total Dissolved Solids regulations. Further, on July 22, 2011, the Pennsylvania Governor's Marcellus Shale Advisory Commission released its report setting forth 96 recommendations on a variety of issues related to natural gas development in Pennsylvania. These recommendations are related to infrastructure; public health, safety, and environmental protection; local impact and emergency response; and economic and workforce development. The Commission made the most recommendations in the area of public health, safety and environmental protection, including doubling penalties authorized for violations of the Oil and Gas Act; increasing bonding requirements; authorizing the PaDEP to suspend, revoke or deny permits on a quicker timeframe for violations or failure to correct violations; expanding a well operator's presumed liability for impaired water quality; amending well stimulation and completion reporting requirements to require disclosure of hazardous chemicals used in fracturing; and other issues related to fracturing operations. Some or all of these recommendations will likely be acted upon and may result in the adoption of new laws and regulations governing shale gas development in the Marcellus Shale in Pennsylvania that could result in substantial changes in the way natural gas activities are conducted in the area. If these types of conditions are imposed, we could be subject to increased costs and possibly limits on the productivity of certain wells.

Certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

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Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the U.S. Securities and Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

Further, on July 28, 2011, the EPA issued proposed rules that would subject oil and gas production, processing, transmission, storage and distribution operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion techniques developed in the EPA's Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these proposed rules could have on our business. Final action on the proposed rules is expected by April 2012.

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. In the United States, climate change action is evolving at the state, regional and federal levels. On December 17, 2010, the EPA amended the "Mandatory Reporting of Greenhouse Gases" final rule ("Reporting Rule") originally issued in September 2009. 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, following issuance of the Endangerment Finding, EPA promulgated final motor vehicle GHG emission standards on April 1, 2010, the effect of which could reduce demand for motor fuels refined from crude oil. Also, according to the EPA, the final motor vehicle GHG standards will trigger construction and operating permit requirements for stationary sources. Thus, on June 3, 2010, EPA issued a final rule to address permitting of GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration ("PSD") and Title V programs. This final rule "tailors" the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi step process, with the largest sources first subject to permitting. In addition, on November 8, 2010, EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to EPA's GHG Reporting Rule. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO_2 equivalent per year will now be required to report annual GHG emissions to EPA, with the first report due on September 28, 2012.

Internationally, 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 extend the Kyoto Protocol's expiration date of 2012 and to develop a treaty to replace the Kyoto Protocol after its expiration. 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.

Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. To the extent that such unfavorable weather conditions are exacerbated by global climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make estimating any future financial risk to our operations caused by these potential physical risks of climate change extremely challenging.

Certain federal income tax law changes have been proposed that, if passed, would have an adverse effect on our financial position, results of operations, and cash flows.

Substantive changes to existing federal income tax laws have been proposed that, if adopted, would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and would impose new taxes. The proposals include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; increase in the taxation of foreign source income; 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 proposals 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 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.

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

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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 3. LEGAL PROCEEDINGS

Legal Matters

The information set forth under the heading "Legal Matters" in Note 7 of the Notes to Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K is incorporated by reference in response to this item.

In August 2011, the Company received a subpoena from the New York Attorney General's Office requesting documents and information regarding the Company's shale and unconventional reservoir reserves calculations. The Company is providing documents and information responsive to the request and is cooperating with the Attorney General's Office in the matter.

Environmental Matters

The information set forth under the heading "Environmental Matters" in Note 7 of the Notes to Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K is incorporated by reference in response to this item.

The Company has received a number of Notices of Violation from the Pennsylvania Department of Environmental Protection (PaDEP) relating to alleged violations, primarily with respect to the Pennsylvania Clean Streams Law, the Pennsylvania Oil and Gas Act and the Pennsylvania Solid Waste Management Act and the rules and regulations promulgated thereunder. The Company has responded to these Notices of Violation, has remediated the areas in question and is actively cooperating with the PaDEP. While the Company cannot predict with certainty whether these Notices of Violation will result in fines and/or penalties, if fines and/or penalties are imposed, the aggregate of these fines and/or penalties could result in monetary sanctions in excess of $100,000.

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ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information as of February 17, 2012 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	58	Chairman, President and Chief Executive Officer	2001
Scott C. Schroeder	49	Vice President, Chief Financial Officer and Treasurer	1997
G. Kevin Cunningham	58	Vice President, General Counsel	2010
Robert G. Drake	64	Vice President, Information Services and Operational Accounting	1998
Jeffrey W. Hutton	56	Vice President, Marketing	1995
Todd L. Liebl	54	Vice President, Land and Business Development	2012
Steven W. Lindeman	51	Vice President, Engineering and Technology	2011
Lisa A. Machesney	56	Vice President	1995
James M. Reid	60	Vice President, Regional Manager South Region	2009
Phillip L. Stalnaker	52	Vice President, Regional Manager North Region	2009
Todd M. Roemer	41	Controller	2010
Deidre L. Shearer	44	Managing Counsel and Corporate Secretary	2012

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, except for Mr. G. Kevin Cunningham, Mr. Todd L. Liebl, Mr. Todd M. Roemer and Ms. Deidre L. Shearer.

Mr. Cunningham joined the Company in November 2009 as Associate General Counsel and was appointed as General Counsel in September 2010 and promoted to Vice President in 2011. Before joining the Company, Mr. Cunningham was Regional Counsel-Southern Division at Chesapeake Energy from 2006 until November 2009. He is a graduate of the University of Texas School of Law and has worked at Fortune 500 E&P companies in both legal and business positions since 1982.

Mr. Liebl joined the Company in September 2008 as South Region Land Manager, promoted to Director of Land in June 2010, Director of Land and Business Development in February 2011 and Vice President in February 2012. Previously, Mr. Liebl held positions with Anadarko Petroleum and most recently Chesapeake Energy from April 2007 until he joined the Company. He holds a Bachelor of Business Administration degree in Petroleum Land Management from the University of Oklahoma.

Mr. Roemer joined the Company in February 2010 after a 14 year career in PricewaterhouseCoopers' energy practice. He is a graduate of the University of Houston Clear Lake with a Bachelor of Science degree in Accounting. Mr. Roemer is a Certified Public Accountant.

Ms. Shearer joined the Company in December 2011 and was appointed Managing Counsel and Corporate Secretary in February 2012. Prior to joining the Company, Ms. Shearer was Assistant General Counsel of KBR, Inc., from January 2007, where she was responsible for corporate governance and SEC and NYSE compliance matters. Ms. Shearer received her J.D. degree from The University of Texas School of Law in 1992 and was primarily in private practice until she joined KBR.

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PART II

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

Our common stock is listed and principally traded on the New York Stock Exchange under the ticker symbol "COG." The following table presents the high and low closing sales prices per share of our common stock during certain periods, as reported in the consolidated transaction reporting system. Cash dividends paid per share of the common stock are also shown. A regular dividend has been declared each quarter since we became a public company in 1990.

On January 3, 2012, the Board of Directors declared a 2-for-1 split of our common stock in the form of a stock dividend. The stock dividend was distributed on January 25, 2012 to shareholders of record on January 17, 2012. All common stock accounts and per share data, including cash dividends per share, have been retroactively adjusted to give effect to the 2-for-1 split of our common stock.

	High	Low	Dividends
2011			
First Quarter	**$ 26.70**	**$ 18.72**	**$ 0.015**
Second Quarter	**$ 33.16**	**$ 25.47**	**$ 0.015**
Third Quarter	**$ 38.56**	**$ 29.65**	**$ 0.015**
Fourth Quarter	**$ 44.30**	**$ 29.29**	**$ 0.015**
2010			
First Quarter	$ 23.12	$ 18.20	$ 0.015
Second Quarter	$ 20.26	$ 15.17	$ 0.015
Third Quarter	$ 16.81	$ 13.50	$ 0.015
Fourth Quarter	$ 18.93	$ 14.14	$ 0.015

As of February 1, 2012, there were 470 registered holders of the common stock.

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 2011, we did not repurchase any shares of common stock. All purchases executed to date have been through open market transactions. The maximum number of remaining shares that may be purchased under the plan as of December 31, 2011 was 9,590,600, after giving effect to the 2-for-1 stock split effected in January 2012.

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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 2006 through December 2011. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2006 and that all dividends were reinvested.

Calculated Values*	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
S&P 500	$ 100.00	$ 105.49	$ 66.46	$ 84.05	$ 96.71	$ 98.75
COG	$ 100.00	$ 133.54	$ 86.27	$ 145.14	$ 126.48	$ 254.16
Dow Jones US Exploration & Production	$ 100.00	$ 143.67	$ 86.02	$ 120.92	$ 141.16	$ 135.25

*

Year-end closing values.

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.

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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,				
(In thousands, except per share amounts)	**2011**	**2010**	**2009**	**2008**	**2007**
Statement of Operations Data					
Operating Revenues	**$ 979,864**	$ 863,104	$ 893,085	$ 956,746	$ 741,130
Impairment of Oil and Gas Properties and Other Assets		40,903	17,622	35,700	4,614
Gain / (Loss) on Sale of Assets[1]	**63,382**	106,294	(3,303)	1,143	13,448
Gain on Settlement of Dispute[2]				51,906	
Income from Operations	**306,850**	266,439	282,269	372,012	274,693
Net Income	**122,408**	103,386	148,343	211,290	167,423
Basic Earnings per Share[3]	**$ 0.59**	$ 0.50	$ 0.72	$ 1.05	$ 0.87
Diluted Earnings per Share[3]	**$ 0.58**	$ 0.49	$ 0.71	$ 1.04	$ 0.86
Dividends per Common Share[3]	**$ 0.06**	$ 0.06	$ 0.06	$ 0.06	$ 0.06
Balance Sheet Data					
Properties and Equipment, Net	**$ 3,934,584**	$ 3,762,760	$ 3,358,199	$ 3,135,828	$ 1,908,117
Total Assets	**4,331,493**	4,005,031	3,683,401	3,701,664	2,208,594
Current Portion of Long-Term Debt				35,857	20,000
Long-Term Debt	**950,000**	975,000	805,000	831,143	330,000
Stockholders' Equity	**2,104,768**	1,872,700	1,812,514	1,790,562	1,070,257

(1) *Gain on Sale of Assets in 2011 includes $34.2 million gain from the sale of certain Haynesville and Bossier Shale oil and gas properties and an aggregate gain of $29.2 million from the sale of various other properties during the year. Gain on Sale of Assets in 2010 includes $40.7 million from the sale of the Company's investment in Tourmaline, $49.3 million from the sale of our Pennsylvania gathering infrastructure and an aggregate gain of $16.3 million from the sale of various other properties during the year. Gain on Sale of Assets for 2007 includes $12.3 million related to the disposition of our remaining offshore portfolio and certain south Louisiana properties.*

(2) *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.*

(3) *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 January 25, 2012.*

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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.

As a result of our production growth and the commencement of various transportation and gathering agreements in 2011, we began separately reporting our transportation and gathering costs as a component of operating expenses in the Consolidated Statement of Operations. Previously reported transportation and gathering costs were reflected as a component of Natural Gas Revenues and have been reclassified to conform to current year presentation. Accordingly, previously reported operating revenues and operating expenses have increased with no impact on previously reported net income.

On January 3, 2012, the Board of Directors declared a 2-for-1 split of our common stock in the form of a stock dividend. The stock dividend was distributed on January 25, 2012 to shareholders of record as of January 17, 2012. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of our common stock.

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.

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, crude oil and, to a lesser extent, natural gas liquids from its properties in the continental United States. 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.

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 that meet our strategic objectives. 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. Our realized natural gas and crude oil price was $4.46 per Mcf and $90.49 per Bbl, respectively, in 2011. In an effort to manage commodity price risk, we opportunistically enter into natural gas and crude oil price swaps and collars. These financial instruments are a component 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

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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 table below illustrates how natural gas prices have fluctuated by month over 2010 and 2011. "Index" represents the first of the month Henry Hub index price per Mmbtu. The "2010" and "2011" price is the natural gas price per Mcf realized by us and includes the realized impact of our natural gas derivative instruments, as applicable:

Natural Gas Prices by Month 2011

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	**$ 4.22**	**$ 4.32**	**$ 3.79**	**$ 4.24**	**$ 4.38**	**$ 4.33**	**$ 4.36**	**$ 4.38**	**$ 3.85**	**$ 3.76**	**$ 3.51**	**$ 3.36**
2011	**$ 4.64**	**$ 4.97**	**$ 4.46**	**$ 4.76**	**$ 4.72**	**$ 4.55**	**$ 4.71**	**$ 4.70**	**$ 4.33**	**$ 4.14**	**$ 3.89**	**$ 4.03**

Natural Gas Prices by Month 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 5.82	$ 5.28	$ 4.81	$ 3.84	$ 4.27	$ 4.16	$ 4.73	$ 4.78	$ 3.64	$ 3.84	$ 3.29	$ 4.27
2010	$ 7.10	$ 6.61	$ 6.43	$ 5.52	$ 5.66	$ 5.76	$ 5.81	$ 5.76	$ 5.00	$ 5.13	$ 4.80	$ 5.57

The table below illustrates how crude oil prices have fluctuated by month over 2010 and 2011. "Index" represents the NYMEX monthly average crude oil price. The "2010" and "2011" price is the crude oil price per Bbl realized by us and includes the realized impact of our crude oil derivative instruments:

Crude Oil Prices by Month 2011

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	**$ 88.81**	**$ 88.86**	**$ 93.57**	**$ 104.00**	**$ 108.15**	**$ 99.49**	**$ 93.40**	**$ 98.14**	**$ 84.12**	**$ 86.89**	**$ 85.30**	**$ 97.41**
2011	**$ 84.65**	**$ 85.19**	**$ 92.37**	**$ 96.16**	**$ 95.44**	**$ 93.82**	**$ 92.99**	**$ 85.17**	**$ 83.59**	**$ 86.99**	**$ 93.97**	**$ 94.46**

Crude Oil Prices by Month 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 72.47	$ 77.62	$ 80.16	$ 81.25	$ 83.45	$ 68.01	$ 77.21	$ 77.44	$ 73.46	$ 73.52	$ 81.77	$ 81.51
2010	$ 101.75	$ 96.32	$ 95.25	$ 97.07	$ 94.48	$ 98.82	$ 99.00	$ 101.47	$ 94.95	$ 101.01	$ 97.51	$ 100.24

Natural gas revenues increased from 2010 to 2011 as a result of increased natural gas production, partially offset by decreased commodity prices. Crude oil revenues increased from 2010 to 2011 primarily due to increased crude oil production partially offset by decreased realized prices. Prices, including the realized impact of derivative instruments, decreased by 22% for natural gas and 8% for crude oil.

We drilled 161 gross wells with a success rate of over 99% in 2011 compared to 113 gross wells with a success rate of 98% in 2010. Total capital and exploration expenditures increased by $14.0 million to $905.5 million in 2011 compared to $891.5 million in 2010. The increase in spending was substantially driven by an expanded Marcellus shale horizontal drilling program and increases in our drilling programs in the Eagle Ford oil shale in south Texas and the Marmaton oil play in Oklahoma. We believe our cash on hand and operating cash flow in 2012 will be sufficient to fund our budgeted capital and exploration spending between $750 and $790 million. Any additional needs are expected to be funded by borrowings from our credit facility.

Our 2012 strategy will remain consistent with 2011. While we consider acquisitions from time to time, we remain focused on pursuing drilling opportunities that provide more predictable results on our

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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. For 2012, we have allocated our planned program for capital and exploration expenditures primarily to the Marcellus shale in northeast Pennsylvania, the Eagle Ford oil shale in south Texas and, to a lesser extent, the Marmaton oil play in Oklahoma. We believe these strategies are appropriate for our portfolio of projects and the current commodity pricing 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 2011 were from funds generated from the sale of natural gas and crude oil production (including hedge realizations), borrowings under our credit facility and the sales of properties and other assets during the year. These cash flows were primarily used to fund our capital and exploration expenditures, in addition to repayments of debt and related interest, contributions to our pension plans and dividends. See below for additional discussion and analysis of cash flow.

We generate cash from the sale of natural gas and crude oil. Operating cash flow fluctuations are substantially driven by commodity prices and changes in our production volumes. Prices for crude oil and natural gas have historically been volatile, including seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have also influenced prices throughout the recent years. 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 revenues.

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 availability under our credit facility and liquidity available to meet our working capital requirements.

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
Cash Flows Provided by Operating Activities	**$ 501,839**	$ 484,911	$ 614,052
Cash Flows Used in Investing Activities	**(487,620)**	(613,741)	(531,027)
Cash Flows Provided by / (Used in) Financing Activities	**(40,257)**	144,621	(70,968)
Net Increase / (Decrease) in Cash and Cash Equivalents	**$ (26,038)**	$ 15,791	$ 12,057

Operating Activities

Key components impacting net operating cash flows are commodity prices, production volumes and operating expenses. Net cash provided by operating activities in 2011 increased by $16.9 million over 2010. This increase was primarily due to increased operating income in 2011 as a result of higher operating revenues that outpaced the increase in operating expenses. This increase was offset by changes in working capital which decreased operating cash flows. The increase in operating revenues was primarily due to an increase in equivalent production partially offset by lower realized natural gas and crude oil prices. Equivalent production volumes increased by 44% for 2011 compared to 2010 as a result of higher natural gas and crude oil production. Average realized natural gas prices decreased by

22% for 2011 compared to 2010. Average realized crude oil prices decreased by 8% compared to the same period.

Net cash provided by operating activities in 2010 decreased by $129.1 million over 2009. This decrease was mainly due to a decrease in oil and gas revenues and higher operating and interest expense. Average realized natural gas prices decreased by 25% in 2010 compared to 2009 and average realized crude oil prices increased by 14% over the same period. Equivalent production volumes increased by 27% in 2010 compared to 2009 primarily due to higher natural gas and crude oil production.

See "Results of Operations" for additional information relative to commodity price, production and operating expense movements. 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 decline in future periods.

Investing Activities

The primary use of cash in investing activities was capital and exploration expenditures. We established the budget for these amounts based on our current estimate of future commodity prices 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 $126.1 million from 2010 to 2011 and increased by $82.7 million from 2009 to 2010. The decrease from 2010 to 2011 was due to an increase of $160.1 million of proceeds from the sale of assets partially offset by an increase of $34.0 million in capital and exploration expenditures.

The increase from 2009 to 2010 was due to an increase of $246.0 million in capital and exploration expenditures partially offset by an increase of $163.3 million of proceeds from the sale of assets.

Financing Activities

Cash flows used in financing activities increased by $184.9 million from 2010 to 2011. This was primarily due to a decrease in borrowings of $195.0 million, partially offset by a decrease in cash paid for capitalized debt issuance costs of $12.8 million.

At December 31, 2011, we had $188.0 million of borrowings outstanding under our unsecured credit facility at a weighted-average interest rate of 4.9% and $711.0 million available for future borrowing.

Cash flows provided by financing activities increased by $215.6 million from 2009 to 2010. This was primarily due to an increase in borrowings of $420.0 million, partially offset by an increase in repayments of debt of $188.0 million, an increase in cash paid for capitalized debt issuance costs by a total of $3.4 million and a decrease of $13.7 million in the tax benefit associated with stock-based compensation.

In December 2010, we completed a private placement of $175.0 million aggregate principal amount of senior unsecured fixed-rate notes with a weighted-average interest rate of 5.58%, consisting of amounts due in January 2021, 2023 and 2026.

In September 2010, we amended and restated our revolving credit facility (credit facility) to increase the available credit line to $900 million with an accordion feature allowing us to increase the available credit line to $1.0 billion, if any one or more of the existing banks or new banks agree to provide such increased commitment amount, and to extend the term to September 2015. 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.

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The amended facility provided for an initial $1.5 billion borrowing base. Effective April 1, 2011, the lenders under our revolving credit facility approved an increase in our borrowing base from $1.5 billion to $1.7 billion as part of the annual redetermination under the terms of the credit facility. Our plan to sell certain oil and gas properties located in Colorado, Utah and Wyoming triggered an interim redetermination of our borrowing base and the $1.7 billion borrowing base was reaffirmed by the lenders effective September 27, 2011.

In June 2010, we amended the agreements governing our senior notes to amend the required asset coverage ratio (the present value of our proved reserves plus working capital to debt) contained in the agreements. The amendment also changed the ratio for maximum calculated indebtedness to borrowing base (as defined in the credit facility agreement).

We strive to manage our debt at a level below the available credit line in order to maintain borrowing capacity. Our credit facility includes a covenant limiting our total debt. Management believes that, with internally generated cash, existing cash on hand and availability under our credit facility, we have the capacity to finance our spending plans and maintain our strong financial position.

Capitalization

Information about our capitalization is as follows:

	December 31,	
(Dollars in thousands)	**2011**	**2010**
Debt[(1)]	**$ 950,000**	$ 975,000
Stockholders' Equity	**$ 2,104,768**	$ 1,872,700
Total Capitalization	**$ 3,054,768**	$ 2,847,700
Debt to Capitalization	**31%**	34%
Cash and Cash Equivalents	**$ 29,911**	$ 55,949

(1) *Includes $188.0 million and $213.0 million of borrowings outstanding under our revolving credit facility at December 31, 2011 and 2010, respectively.*

For the year ended December 31, 2011, we paid dividends of $12.5 million ($0.06 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, borrowings under our credit facility. We budget these capital expenditures based on our projected cash flows for the year.

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The following table presents major components of our capital and exploration expenditures:

(In thousands)	Year Ended December 31, 2011	2010	2009
Capital Expenditures			
Drilling and Facilities	**$ 780,673**	$ 654,153	$ 401,143
Leasehold Acquisitions	**71,134**	130,675	145,681
Acquisitions		801	394
Pipeline and Gathering	**7,378**	54,811	32,861
Other	**9,840**	8,368	9,506
	869,025	848,808	589,585
Exploration Expense	**36,447**	42,725	50,784
Total	**$ 905,472**	$ 891,533	$ 640,369

We plan to drill approximately 120 to 130 gross wells in 2012 compared with 161 gross wells drilled in 2011. This 2012 drilling program includes between $750 and $790 million in total capital and exploration expenditures, down from $905.5 million in 2011. This decrease is primarily due to decreased drilling activity as a result of lower commodity prices. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease our capital and exploration expenditures accordingly.

Contractual Obligations

Our material contractual obligations include long-term debt, interest on long-term debt, gas transportation agreements, drilling rig commitments, hydraulic fracturing services 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, 2011 are set forth in the following table:

		Payments Due by Year			
(In thousands)	Total	2012	2013 to 2014	2015 to 2016	2017 & Beyond
Long-Term Debt	**$ 950,000**	$	$ 75,000	$ 208,000	$ 667,000
Interest on Long-Term Debt[(1)]	**392,802**	60,163	109,285	89,464	133,890
Gas Transportation Agreements[(2)]	**1,853,329**	84,285	237,327	244,726	1,286,991
Drilling Rig Commitments[(2)]	**45,881**	19,766	26,115		
Hydraulic Fracturing Services Commitments[(2)]	**82,207**	82,207			
Operating Leases[(2)]	**18,635**	5,656	9,902	3,077	
Total Contractual Obligations	**$ 3,342,854**	$ 252,077	$ 457,629	$ 545,267	$ 2,087,881

(1) *Interest payments have been calculated utilizing the fixed rates of our $762.0 million long-term debt outstanding at December 31, 2011. Interest payments on our revolving credit facility were calculated by assuming that the December 31, 2011 outstanding balance of $188.0 million will be outstanding through the September 2015 maturity date. A constant interest rate of 4.9% was assumed, which was the December 31, 2011 weighted-average interest rate. Actual results will differ from these estimates and assumptions.*

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

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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, 2011 was $60.1 million, down from $72.3 million at December 31, 2010. This decrease is primarily due to $12.1 million of liabilities divested, $3.6 million in downward revisions of previous estimates and $1.2 million in liabilities settled, partially offset by $3.3 million in accretion expense during 2011 and $1.5 million of liabilities incurred. See Note 8 of the Notes to the Consolidated Financial Statements for further details.

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. Our most significant policies are discussed below.

Successful Efforts Method of Accounting

We follow the successful efforts method of accounting for our oil and gas producing activities. Acquisition costs for proved and unproved properties are capitalized when incurred. Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry hole costs are expensed. Development costs, including costs to drill and equip development wells and successful exploratory drilling costs to locate proved reserves are capitalized.

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. Any significant variance in the interpretations or assumptions could materially affect the estimated quantity and value of our reserves.

Our reserves have been prepared by our petroleum engineering staff and audited by Miller & Lents, Ltd., independent petroleum engineers, who in their opinion determined the estimates presented to be reasonable in the aggregate. For more information regarding reserve estimation, including historical reserve revisions, refer to the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8.

Our rate of recording DD&A expense is dependent upon our estimate of proved and proved developed reserves, which are 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 uneconomic 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 ($0.05) to $0.06 per Mcfe. Revisions in significant fields may individually affect our DD&A rate. It is estimated that a positive or negative reserve revision of 10% in one of our most productive fields would have a ($0.05) to $0.06 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 our oil and gas properties for impairment 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. In the event that commodity prices remain low or continue to decline, there could be a significant revision in the future. Fair value is calculated by discounting the future cash flows. The discount factor used 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 crude oil.

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 drilling and exploration experience and average property lives. Average property lives are determined on a geographical basis and based on the estimated life of unproved property leasehold rights. Historically, the average property life in each of the geographical areas has not significantly changed and generally range from three to five years. The commodity price environment may impact the capital available for exploration projects as well as development drilling. We have considered these impacts when determining the amortization rate 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 $23.8 million or decrease by approximately $15.6 million, respectively, per year.

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 and development program.

Natural gas prices have decreased from an average price of $4.39 per Mmbtu in 2010 to an average price of $4.04 per Mmbtu in 2011. Natural gas prices were $3.36 per Mmbtu in December 2011 and have continued to decline to $2.68 per Mmbtu in February 2012. Natural gas prices represent the first of the month Henry Hub index price per Mmbtu. Oil prices have increased from an average price of $77.32 per barrel in 2010 to an average price of $94.01 per barrel in 2011. Any further decline in natural gas prices or quantities could result in an impairment of proved oil and gas properties.

Asset Retirement Obligation

The majority of our asset retirement obligation (ARO) relates to the plugging and abandonment of oil and gas wells and to a lesser extent meter stations, pipelines, processing plants and compressors. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. The recognition of an asset retirement obligation requires management to make assumptions that include estimated plugging and abandonment costs, timing of settlements, inflation rates and discount rate. In periods subsequent to initial measurement, the asset retirement

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cost is allocated to expense using a systematic and rational method over the assets' useful life, while increases in the discounted ARO liability resulting from the passage of time (accretion expense) are reflected as depreciation, depletion and amortization expense.

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. 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 are recorded currently in earnings as a component of Natural Gas and Crude Oil and Condensate revenue in the Consolidated Statement of Operations.

The fair value of our derivative instruments are measured based on quotes from the Company's counterparties. Such quotes have been derived using valuation models that consider 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 as applicable. These estimates are verified using relevant NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions. In times where we have net derivative contract liabilities, our nonperformance risk is evaluated using a market credit spread provided by our bank.

Employee Benefit Plans

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. Significant assumptions used to determine our projected pension obligation and related costs include discount rates, expected return on plan assets, and rate of compensation increases, while the assumptions used to determine our postretirement benefit obligation and related costs include discount rates and health care cost trends. See Note 5 of the Notes to the Consolidated Financial Statements for a full discussion of our employee benefit plans.

Stock-Based Compensation

We account for stock-based compensation under a fair value based method of accounting prescribed under ASC 718. Under the fair value method, compensation cost is measured at the grant date and remeasured each reporting period for liability-classified awards based on the fair 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. The use of these models requires significant judgment with respect to expected life, volatility and other factors. Stock-based compensation cost for all types of awards is included in General and Administrative expense in the Consolidated Statement of Operations. See Note 11 of the Notes to the Consolidated Financial Statements for a full discussion of our stock-based compensation.

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Recently Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs." The amendments in this update generally represent clarifications of Topic 820, but also include some instances where a particular principle or requirement for measuring fair value or disclosing information about fair value measurements has changed. This update results in common principles and requirements for measuring fair value and for disclosing information about fair value measurements in accordance with U.S. GAAP and IFRS. The amendments in this update are to be applied prospectively. The amendments are effective for interim and annual periods beginning after December 15, 2011. Early application is not permitted. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, "Presentation of Comprehensive Income." This update was amended in December 2011 by ASU No. 2011-12, "Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05." This update defers only those changes in update 2011-05 that relate to the presentation of reclassification adjustments. All other requirements in update 2011-05 are not affected by this update, including the requirement to report comprehensive income either in a single continuous financial statement or in two separate but consecutive financial statements. ASU No. 2011-05 and 2011-12 are effective for fiscal years (including interim periods) beginning after December 15, 2011. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In December 2011, the FASB issued ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities." The amendments in this update require enhanced disclosures around financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. We do not expect this guidance to have any impact on our consolidated financial position, results of operations or cash flows.

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 and an asset coverage ratio of the present value of proved reserves plus working capital to debt of 1.75 to 1.0. Our revolving credit agreement also requires us to maintain a current ratio of 1.0 to 1.0. At December 31, 2011, we were in compliance in all material respects with all restrictive covenants on both the revolving credit agreement and senior 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.

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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 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 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 more significant 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 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 collar 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.

Forward-Looking Information

The statements regarding future financial and operating performance and results, market prices, future hedging activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "forecast," "predict," "may," "should," "could," "will" and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including geographic basis differentials) of natural gas and oil, results for future drilling and marketing activity, future production and costs, electronic, cyber or physical security breaches 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.

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RESULTS OF OPERATIONS

2011 and 2010 Compared

We reported net income for 2011 of $122.4 million, or $0.59 per share. During 2010, we reported net income of $103.4 million, or $0.50 per share. Net income increased in 2011 by $19.0 million, primarily due to increased operating revenues, partially offset by increased operating expenses, decreased gain on sale of assets and increased income tax and interest expenses. Operating revenues increased by $116.8 million largely due to increased natural gas and crude oil and condensate revenues, partially offset by a decrease in brokered natural gas revenues. Operating expenses increased by $33.4 million between periods primarily due to increases in transportation and gathering expenses, general and administrative expenses, depreciation, depletion and amortization and direct operations, partially offset by a decrease in impairment of oil and gas properties and lower brokered natural gas cost, taxes other than income and exploration expense.

Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

	Year Ended December 31,		Variance	
	2011	**2010**	**Amount**	**Percent**
Revenue Variances (In thousands)				
Natural Gas[1]	**$ 797,482**	$ 713,872	$ 83,610	12 %
Brokered Natural Gas	**51,190**	65,281	(14,091)	(22)%
Crude Oil and Condensate	**125,972**	79,091	46,881	59 %
Other	**6,185**	5,086	1,099	22 %

(1) *Natural Gas Revenues exclude the unrealized loss of $1.0 million and $0.2 million from the change in fair value of our derivatives not designated as hedges in 2011 and 2010, respectively.*

	Year Ended December 31,		Variance		Increase (Decrease)
	2011	**2010**	**Amount**	**Percent**	**(In thousands)**
Price Variances					
Natural Gas[1]	**$ 4.46**	$ 5.69	$ (1.23)	(22)%	$ (219,624)
Crude Oil and Condensate[2]	**$ 90.49**	$ 97.91	$ (7.42)	(8)%	(10,331)
Total					$ (229,955)
Volume Variances					
Natural Gas (Mmcf)	**178,848**	125,474	53,374	43%	$ 303,234
Crude Oil and Condensate (Mbbl)	**1,392**	808	584	72%	57,212
Total					$ 360,446

(1) *These prices include the realized impact of derivative instrument settlements, which increased the price by $0.47 per Mcf in 2011 and by $1.23 per Mcf in 2010.*

(2) *These prices include the realized impact of derivative instrument settlements, which increased the price by $1.01 per Bbl in 2011 and by $22.31 per Bbl in 2010.*

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Natural Gas Revenues

The increase in Natural Gas revenues of $83.6 million, excluding the impact of the unrealized losses discussed above, is primarily due to increased production, partially offset by lower realized natural gas prices. The increased production is primarily due to increased production associated with our Marcellus Shale drilling program in northeast Pennsylvania, partially offset by decreases in production primarily in east and south Texas due to normal production declines, the sale of oil and gas properties in Colorado, Utah and Wyoming and a shift from gas to oil projects.

Crude Oil and Condensate Revenues

The increase in Crude Oil and Condensate revenues of $46.9 million is primarily due to increased production, partially offset by lower realized oil prices. The increase in production is primarily due to our drilling program in the Eagle Ford oil shale in south Texas, partially offset by lower production in east Texas due to decreased activity.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31,		Variance		Price and Volume Variances
	2011	**2010**	**Amount**	**Percent**	**(In thousands)**
Brokered Natural Gas Sales					
Sales Price ($/Mcf)	**$ 4.97**	$ 5.41	$ (0.44)	(8)%	$ (4,533)
Volume Brokered (Mmcf)	**x 10,303**	x 12,072	(1,769)	(15)%	(9,558)
Brokered Natural Gas Revenues (In thousands)	**$ 51,190**	$ 65,281			$ (14,091)
Brokered Natural Gas Purchases					
Purchase Price ($/Mcf)	**$ 4.25**	$ 4.68	$ (0.43)	(9)%	$ 4,353
Volume Brokered (Mmcf)	**x 10,303**	x 12,072	(1,769)	(15)%	8,279
Brokered Natural Gas Cost (In thousands)	**$ 43,834**	$ 56,466			$ 12,632
Brokered Natural Gas Margin (In thousands)	**$ 7,356**	$ 8,815			$ (1,459)

The decreased brokered natural gas margin of $1.5 million is primarily a result of a decrease in brokered volumes coupled with a decrease in the sales price that slightly outpaced the decrease in purchase price.

Impact of Derivative Instruments on Operating Revenues

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

	Year Ended December 31,			
	2011		**2010**	
(In thousands)	**Realized**	**Unrealized**	**Realized**	**Unrealized**
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas	**$ 84,937**	**$**	$ 154,960	$
Crude Oil	**1,403**		18,030	
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		**(965)**		(226)
	$ 86,340	**$ (965)**	$ 172,990	$ (226)

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Operating and Other Expenses

(In thousands)	Year Ended December 31, 2011	2010	Variance Amount	Percent
Operating and Other Expenses				
Brokered Natural Gas Cost	**$ 43,834**	$ 56,466	$ (12,632)	(22)%
Direct Operations	**107,409**	99,642	7,767	8 %
Transportation and Gathering	**73,322**	19,069	54,253	285 %
Taxes Other Than Income	**27,576**	37,894	(10,318)	(27)%
Exploration	**36,447**	42,725	(6,278)	(15)%
Depreciation, Depletion and Amortization	**343,141**	327,083	16,058	5 %
Impairment of Oil and Gas Properties and Other Assets		40,903	(40,903)	(100)%
General and Administrative	**104,667**	79,177	25,490	32 %
Total Operating Expense	**$ 736,396**	$ 702,959	$ 33,437	5 %
(Gain) / Loss on Sale of Assets	**$ (63,382)**	$ (106,294)	$ (42,912)	(40)%
Interest Expense and Other	**71,663**	67,941	3,722	5 %
Income Tax Expense	**112,779**	95,112	17,667	19 %

Total costs and expenses from operations increased by $33.4 million from 2010 to 2011. The primary reasons for this fluctuation are as follows:

Brokered Natural Gas Cost decreased by $12.6 million from 2010 to 2011. See the preceding table titled "Brokered Natural Gas Revenue and Cost" for further analysis.

Direct Operations increased $7.8 million largely due to increased operating costs primarily driven by increased production. Contributing to the increase are higher workover and environmental and regulatory costs associated with the remediation of certain wells in northeast Pennsylvania as a result of the PaDEP consent order and settlement agreement. Offsetting these increases were lower lease maintenance, subsurface lease maintenance and plugging and abandonment costs in 2011 compared to 2010 coupled with lower compression expenses primarily due to the sale of our gathering system in northeast Pennsylvania in the fourth quarter of 2010.

Transportation and Gathering increased by $54.3 million primarily due to the commencement of various firm transportation and gathering arrangements in 2011, primarily in northeast Pennsylvania.

Taxes Other Than Income decreased $10.3 million due to decreased production taxes as a result of tax refunds and credits received in 2011 on qualifying wells, lower ad valorem tax expense due to lower natural gas prices and property values and lower franchise tax expense.

Exploration decreased $6.3 million due to lower geophysical and geological costs primarily due to a reduction in the acquisition of seismic data, partially offset by higher dry hole costs in 2011 related to an exploratory dry hole in Montana.

Depreciation, Depletion and Amortization increased by $16.1 million, of which $29.8 million was due to increased depreciation and depletion from increased capital spending and higher equivalent production volumes offset by a lower DD&A rate of $1.64 per Mcfe for 2011 compared to $2.12 per Mcfe for 2010 and a $1.4 million increase in accretion of asset retirement obligations. The increase in depletion and depreciation was partially offset by a decrease in amortization of unproved properties of $15.1 million primarily due to a decrease in amortization rates due to a shift in our drilling and development activities.

Impairment of Oil and Gas Properties decreased by $40.9 million from 2011 to 2010 due to the impairment of two south Texas fields recognized as a result of continued price declines and limited activity and the impairment of drilling and service equipment in 2010. There were no impairments in 2011.

General and Administrative increased by $25.5 million primarily due to an increase in stock-based compensation expense of $25.1 million primarily associated with the mark to market of the liability portion of our performance shares as a result of our higher average stock price for the month of December 2011 compared to the average stock price for the month of December 2010. Higher incentive compensation and fringe benefits also contributed to the increase. These increases are partially offset by lower legal and professional costs associated with the PaDEP consent order and settlement agreement executed in 2010.

Gain / (Loss) on Sale of Assets

During 2011, we recognized a gain of $34.2 million from the sale of oil and gas properties in east Texas and an aggregate gain of $29.2 million related to the sale of various other assets as part of our ongoing asset portfolio management program.

During 2010, we recognized a gain of $49.3 million from the sale of our Pennsylvania gathering infrastructure, $40.7 million from the sale of our investment in Tourmaline and an aggregate gain of $16.3 million related to the sale of various other oil and gas properties and other assets during the year.

Interest Expense, Net

Interest Expense and Other increased by $3.7 million in 2011 compared to 2010 primarily due to an increase in the weighted-average effective interest rate on the credit facility, which increased to approximately 4.1% during the 2011 compared to approximately 3.8% during 2010, partially offset by a decrease in weighted-average borrowings under our credit facility based on average daily balances of $317.7 million during 2011 compared to average daily balances of $340.4 million during 2010. In addition, in December 2010, we issued $175 million aggregate principal amount of 5.58% weighted-average fixed rate notes, which increased interest expense recognized in 2011.

Income Tax Expense

Income Tax Expense increased by $17.7 million in 2011 compared to 2010 primarily due to increased pretax income and a slightly higher effective tax rate. The effective tax rates for 2011 and 2010 were 48.0% and 47.9%, respectively. The effective tax rate was slightly higher primarily due to an increase in our state rates used in establishing deferred income taxes mainly due to a continued shift in our state apportionment factors to higher rate states, primarily Pennsylvania, as a result of our continued focus on development of our Marcellus shale properties.

2010 and 2009 Compared

We reported net income for 2010 of $103.4 million, or $0.50 per share. During 2009, we reported net income of $148.3 million, or $0.72 per share. Net income decreased in 2010 by $45.0 million, primarily due to increased operating expenses, income tax and interest expenses and decreased operating revenues partially offset by increased gain on sale of assets. Operating revenues decreased by $30.0 million largely due to decreases in natural gas and brokered natural gas revenues, partially offset by an increase in crude oil and condensate revenues. Operating expenses increased by $95.4 million between periods due primarily to increases in depreciation, depletion and amortization, impairment of oil and gas properties and other assets, general and administrative expense, transportation and

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gathering and direct operations. These increases were partially offset by decreases in brokered natural gas cost, taxes other than income and exploration expense.

Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

	Year Ended December 31,		Variance	
	2010	2009	Amount	Percent
Revenue Variances (In thousands)				
Natural Gas[1]	$ 713,872	$ 745,497	$ (31,625)	(4)%
Brokered Natural Gas	65,281	75,283	(10,002)	(13)%
Crude Oil and Condensate	79,091	69,936	9,155	13 %
Other	5,086	4,323	763	18 %

(1) *Natural Gas Revenues exclude the unrealized loss from the change in fair value of our basis swaps of $0.2 million and $2.0 million in 2010 and 2009, respectively.*

	Year Ended December 31,		Variance		Increase (Decrease)
	2010	2009	Amount	Percent	(In thousands)
Price Variances					
Natural Gas[1]	$ 5.69	$ 7.61	$ (1.92)	(25)%	$ (241,357)
Crude Oil and Condensate[2]	$ 97.91	$ 85.52	$ 12.39	14 %	10,010
Total					$ (231,347)
Volume Variances					
Natural Gas (Mmcf)	125,474	97,914	27,560	28 %	$ 209,732
Crude Oil and Condensate (Mbbl)	808	818	(10)	(1)%	(855)
Total					$ 208,877

(1) *These prices include the realized impact of derivative instrument settlements, which increased the price by $1.23 per Mcf in 2010 and by $3.80 per Mcf in 2009.*

(2) *These prices include the realized impact of derivative instrument settlements, which increased the price by $22.31 per Bbl in 2010 and by $28.85 per Bbl in 2009.*

Natural Gas Revenues

The decrease in Natural Gas revenue of $31.6 million, excluding the impact of the unrealized losses discussed above, is due primarily to the decrease in realized natural gas prices, decreased production in east and south Texas associated with normal production declines, delays in completions and a shift from gas to oil projects, as well as the sale of our Canadian properties in April 2009. Partially offsetting these decreases was an increase in natural gas production in the northeast Pennsylvania associated with increased drilling and the start up of a portion of the Lathrop compressor station in the Marcellus shale at the end of the second quarter of 2010.

Crude Oil and Condensate Revenues

The $9.2 million increase in crude oil and condensate revenues is primarily due to an increase in realized crude oil prices and an increase in crude oil production in the Eagle Ford shale in south Texas and the Pettet formation production in east Texas. These increases are partially offset by lower

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production in West Virginia and northeast Pennsylvania as well as the sale of our Canadian properties in April 2009.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31, 2010	Year Ended December 31, 2009	Variance Amount	Variance Percent	Price and Volume Variances (In thousands)
Brokered Natural Gas Sales					
Sales Price ($/Mcf)	$ 5.41	$ 5.95	$ (0.54)	(9)%	$ (6,527)
Volume Brokered (Mmcf)	x 12,072	x 12,656	(584)	(5)%	(3,475)
Brokered Natural Gas Revenues (In thousands)	$ 65,281	$ 75,283			$ (10,002)
Brokered Natural Gas Purchases					
Purchase Price ($/Mcf)	$ 4.68	$ 5.30	$ (0.62)	(12)%	$ 7,489
Volume Brokered (Mmcf)	x 12,072	x 12,656	(584)	(5)%	3,075
Brokered Natural Gas Cost (In thousands)	$ 56,466	$ 67,030			$ 10,564
Brokered Natural Gas Margin (In thousands)	$ 8,815	$ 8,253			$ 562

The increased brokered natural gas margin of $0.6 million is a result of a decrease in purchase price that outpaced the decrease in sales price, partially offset by a decrease in volumes brokered.

Impact of Derivative Instruments on Operating Revenues

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

(In thousands)	Year Ended December 31, 2010 Realized	2010 Unrealized	2009 Realized	2009 Unrealized
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas	$ 154,960	$	$ 371,915	$
Crude Oil	18,030		23,112	
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		(226)		(1,954)
	$ 172,990	$ (226)	$ 395,027	$ (1,954)

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Operating and Other Expenses

	Year Ended December 31,		Variance	
(In thousands)	**2010**	**2009**	**Amount**	**Percent**
Operating and Other Expenses				
Brokered Natural Gas Cost	$ 56,466	$ 67,030	$ (10,564)	(16)%
Direct Operations	99,642	93,985	5,657	6 %
Transportation and Gathering	19,069	13,809	5,260	38 %
Taxes Other Than Income	37,894	44,649	(6,755)	(15)%
Exploration	42,725			