XTO ENERGY INC

810 HOUSTON ST
FORT WORTH, TX, 76102
817−870−2800
www.xtoenergy.com

10−K

Annual report pursuant to section 13 and 15(d)
Filed on 2/25/2010
Filed Period 12/31/2009

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

Form 10−K

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

For the fiscal year ended December 31, 2009

OR

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

For the transition period from ____ to ____

Commission File Number: 1−10662

XTO Energy Inc.
(Exact name of registrant as specified in its charter)

Delaware	75−2347769	810 Houston Street, Fort Worth, Texas	76102
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)	(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (817) 870−2800

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $.01 par value	**New York Stock Exchange**

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

Indicate by check mark if the registrant is a well−known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S−T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, accelerated filer, a non−accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b−2 of the Exchange Act (check one):

Large accelerated filer	☑		Accelerated filer ☐
Non−accelerated filer	☐	(Do not check if smaller reporting company)	Smaller reporting company ☐

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

As of June 30, 2009, the aggregate market value of the registrant's common stock held by non−affiliates of the registrant was $21.3 billion based on the closing price as reported on the New York Stock Exchange.

Number of Shares of Common Stock outstanding as of February 19, 2010 – 583,344,525

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Part III of this Report is incorporated by reference from the Registrant's Proxy Statement which will be filed with the Commission no later than April 30, 2010.

XTO ENERGY INC.

TABLE OF CONTENTS

PART I

Items 1. and 2. *BUSINESS AND PROPERTIES*

General

XTO Energy Inc. and its subsidiaries (“the Company”) are engaged in the acquisition, development, exploitation and exploration of both producing oil and gas properties and unproved properties, and in the production, processing, marketing and transportation of oil and natural gas. The Company was formerly known as Cross Timbers Oil Company and changed its name to XTO Energy Inc. in June 2001.

On December 13, 2009, we entered into a definitive merger agreement with Exxon Mobil Corporation under which we would become a wholly owned subsidiary of ExxonMobil. As a result of the merger, each outstanding share of our common stock will be converted into 0.7098 shares of ExxonMobil common stock. Completion of the merger remains subject to certain conditions, including the adoption of the merger agreement by our stockholders, as well as certain governmental and regulatory approvals. We currently expect to complete the merger in the second quarter of 2010, however, no assurance can be given as to when, or if, the merger will occur.

Our corporate internet web site is www.xtoenergy.com. We make available free of charge, on or through the investor relations section of our web site, 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 filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. We also make available all of our press releases and investor presentations on our website.

We have grown through acquisition of proved oil and gas reserves and unproved properties, development and exploitation activities and purchases of additional interests in or near our acquired properties. We expect growth in the future to continue to be accomplished through a combination of acquisitions and development. During 2010, our primary emphasis will be on development of our existing property base. We will also continue to review acquisition opportunities including property divestitures by major energy related companies, public exploration and development companies and private energy companies. Completion of additional acquisitions will depend on the quality of properties available, commodity prices, competitive factors, public capital markets and terms of the merger agreement with ExxonMobil.

Our corporate headquarters are located in Fort Worth, Texas at 810 Houston Street (telephone 817−870−2800). Our proved reserves are principally located in relatively long−lived fields with an extensive base of hydrocarbons in place and, in most cases, well−established production histories concentrated in the following areas:

- Eastern Region, including the East Texas Basin, Haynesville Shale, northwestern Louisiana and Mississippi;
- North Texas Region, including the Barnett Shale;
- Mid−Continent and Rocky Mountain Region, including the Fayetteville, Woodford and Bakken Shales;
- San Juan Region;
- Permian Region;
- South Texas and Gulf Coast Region, including the offshore Gulf of Mexico; and
- Other, including Marcellus Shale and North Sea.

We use the following volume abbreviations throughout this Form 10−K. “Equivalent” volumes are computed with oil and natural gas liquid quantities converted to Mcf, or natural gas converted to Bbls, on an energy equivalent ratio of one barrel to six Mcf.

- Bbl — Barrel (of oil or natural gas liquids)
- Bcf — Billion cubic feet (of natural gas)
- Bcfe — Billion cubic feet of natural gas equivalent
- BOE — Barrels of oil equivalent
- MBbls — Thousand barrels (of oil or natural gas liquids)
- Mcf — Thousand cubic feet (of natural gas)
- Mcfe — Thousand cubic feet of natural gas equivalent
- MMBtu — One million British Thermal Units, a common energy measurement
- Tcf — Trillion cubic feet (of natural gas)
- Tcfe — Trillion cubic feet equivalent

Our estimated proved reserves at December 31, 2009 were 12.50 Tcf of natural gas, 93 million Bbls of natural gas liquids and 294 million Bbls of oil, based on a 12−month average realized price of $3.16 per Mcf for gas, $27.18 per Bbl for natural gas liquids and $55.96 per Bbl for oil. On an energy equivalent basis, our proved reserves were 14.83 Tcfe at December 31, 2009, a 7% increase from proved reserves of 13.86 Tcfe at the prior year end. Increased proved reserves during 2009 were primarily the result of development and exploitation activities. On a per Mcfe basis, 61% of proved reserves were proved developed reserves at December 31, 2009. During 2009, our average daily production was 2.34 Bcf of gas, 20.6 MBbls of natural gas liquids and 66.3 MBbls of oil. Fourth quarter 2009 average daily production was 2.37 Bcf of gas, 21.2 MBbls of natural gas liquids and 64.6 MBbls of oil.

Our properties typically have relatively long reserve lives and predictable production profiles. Based on December 31, 2009 proved reserves and projected 2010 production from properties owned as of December 31, 2009, the average reserve−to−production index of our proved reserves is 16.0 years. The projected 2010 production is from proved developed producing reserves as of December 31, 2009. In general, our properties have extensive production histories and production enhancement opportunities. Within each of our geographical regions, we have one or more core areas in which our major producing fields are concentrated. For example, the core area in the North Texas region is the Barnett Shale. This allows for substantial economies of scale in production and cost−effective application of reservoir management techniques gained from prior operations. As of December 31, 2009, we owned interests in 34,657 gross (18,815.8 net) producing wells, and we operated wells representing 85% of the present value of cash flows before income taxes (discounted at 10%) from estimated proved reserves. The high proportion of operated properties allows us to exercise more control over expenses, capital allocation and the timing of development and exploitation activities in our fields.

We have a substantial inventory of identified potential drilling locations. Drilling plans are primarily dependent upon product prices, available cash flow, expected returns, the availability and pricing of drilling equipment and supplies, and gathering, processing and transmission infrastructure.

We employ a disciplined acquisition program refined by senior management to expand our reserve base in core areas and to add new core areas. Our engineers and geologists use their expertise and experience gained through the management of existing core properties to target properties to be acquired with similar geologic and reservoir characteristics. We then use our development and technological knowledge to increase the reserves of acquired properties.

We operate gas gathering, treating and compression facilities in several of our core producing areas. We also operate three gas processing plants, and we own small interests in other nonoperated gas processing plants and facilities. Our gas gathering and processing operations are only in areas where we have production and are considered activities that facilitate our natural gas production and sales operations.

We market our gas production and the gas output of our gathering and processing systems. A large portion of our natural gas is processed, with most of the resultant natural gas liquids being marketed by unaffiliated third parties. We use commodities futures contracts, collars and basis swap agreements, fixed−price physical sales and other price risk management instruments to hedge pricing risks.

History of the Company

The Company was incorporated in Delaware in 1990 to ultimately acquire the business and properties of predecessor entities that were created from 1986 through 1989. Our initial public offering of common stock was completed in May 1993.

During 1991, we formed Cross Timbers Royalty Trust by conveying a 90% net profits interest in substantially all of the royalty and overriding royalty interests that we then owned in Texas, New Mexico and Oklahoma, and a 75% net profits interest in seven nonoperated working interest properties in Texas and Oklahoma. Cross Timbers Royalty Trust units are listed on the New York Stock Exchange under the symbol “CRT.” We no longer have any ownership interest in this trust.

In December 1998, we formed the Hugoton Royalty Trust by conveying an 80% net profits interest in principally gas−producing operated working interests in the Hugoton area of Kansas and Oklahoma, the Anadarko Basin of Oklahoma and the Green River Basin of Wyoming. Hugoton Royalty Trust units are listed on the New York Stock Exchange under the symbol “HGT.” We no longer have any ownership interest in this trust.

Industry Operating Environment

The oil and gas industry is affected by many factors that we generally cannot control. Governmental regulations, particularly in the areas of taxation, energy, climate change and the environment, can have a significant impact on operations and profitability. Crude oil prices are determined by global supply and demand and regional storage and refining capacity. Oil supply is significantly influenced by production levels of OPEC member countries, while demand is largely driven by the condition of worldwide economies, as well as weather. Natural gas prices are generally determined by North American supply and demand and are affected by imports of liquefied natural gas. Weather has a significant impact on demand for natural gas since it is a primary heating resource. Its increased use for electrical generation has kept natural gas demand elevated throughout the year, removing some of the seasonal swing in prices. See “Significant Events, Transactions and Conditions – Product Prices” in Part II, Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations, regarding recent price fluctuations and their effect on our results.

Business Strategy

The primary components of our business strategy are:

- increasing production and reserves through efficient management of operations and through development, exploitation and exploration activities,
- acquiring long−lived, operated oil and gas properties, including undeveloped leases,
- hedging a portion of our production to provide adequate cash flow to fund our development budget and protect the economic return on development projects and acquisitions, and
- retaining management and technical staff that have substantial experience in our core areas.

Increasing Production and Reserves. A principal component of our strategy is to increase production and reserves through aggressive management of operations and low−risk development. We believe that our principal properties possess geologic and reservoir characteristics that make them well suited for production increases through drilling and other development programs. Additionally, we review operations and mechanical data on operated properties to determine if actions can be taken to reduce operating costs or increase production. Such actions include installing, repairing and upgrading lifting equipment, redesigning downhole equipment to improve production from different zones, modifying gathering and other surface facilities and conducting restimulations and recompletions. We may also initiate, upgrade or revise existing secondary recovery operations.

Exploration Activities. During 2010, we plan to focus our exploration activities on projects that are near currently owned productive fields. We believe that we can prudently and successfully add growth potential through exploratory activities given improved technology, our experienced technical staff and our expanded base of operations. We have allocated approximately $75 million of our $3.37 billion 2010 development budget for exploration activities. These exploration activities do not include low risk exploration costs that are classified as development costs for budget purposes.

Acquiring Long−Lived, Operated Properties. We seek to acquire long−lived, operated producing properties that:

- contain complex, multiple−producing horizons with the potential for increases in reserves and production,
- produce from nonconventional sources, including tight natural gas reservoirs, coal bed methane and natural gas− and oil−producing shale formations,
- are in core operating areas or in areas with similar geologic and reservoir characteristics, and
- provide opportunities to improve operating efficiencies.

We believe that the properties we acquire provide opportunities to increase production and reserves through the implementation of mechanical and operational improvements, workovers, behind−pipe completions, secondary recovery operations, new development wells and other development activities. We also seek to acquire facilities related to gathering, processing, marketing and transporting oil and gas in areas where we own reserves. Such facilities can enhance profitability, reduce costs, and provide marketing flexibility and access to additional markets. Our ability to successfully purchase properties is dependent upon, among other things, competition for such purchases and the availability of financing to supplement internally generated cash flow.

We also seek to acquire undeveloped properties that potentially have the same attributes as targeted producing properties.

Hedging Activities. To reduce production price risk, we may enter futures contracts, collars and basis swap agreements, as well as fixed−price physical delivery contracts. Our policy is to consider hedging a portion of our production at commodity prices management deems attractive. While there is a risk we may not be able to realize the full benefit of rising prices, management plans to continue its hedging strategy because of the benefits provided by predictable, stable cash flow, including:

- ability to more efficiently plan and execute our development program, which facilitates predictable production growth,
- ability to help assure the economic return on acquisitions,
- ability to enter long−term arrangements with drilling contractors, allowing us to continue development projects when product prices decline,
- more consistent returns on investment, and
- better utilization of our personnel.

Experienced Management and Technical Staff. Most senior management and technical staff have worked together for over 20 years and have substantial experience in our core operating areas. Bob R. Simpson, Chairman of the Board and Founder, was previously an executive officer of Southland Royalty Company, one of the largest U.S. independent oil and gas producers prior to its acquisition by Burlington Northern, Inc. in 1985. Keith A. Hutton, our Chief Executive Officer, and Vaughn O. Vennerberg, our President, have each been with the Company since 1987.

Other Strategies. We may also acquire working interests in nonoperated producing properties if such interests otherwise meet our acquisition criteria. We attempt to acquire nonoperated interests in fields where the operators have a significant interest to protect, including potential undeveloped reserves that will be exploited by the operator. We may also acquire nonoperated interests in order to ultimately accumulate sufficient ownership interests to operate the properties.

We also attempt to acquire a portion of our reserves as royalty interests. Royalty interests have few operational liabilities because they do not participate in operating activities and do not bear production or development costs.

Royalty Trusts and Publicly Traded Partnerships. We have created and sold units in publicly traded royalty trusts. Sales of royalty trust units allow us to more efficiently capitalize our mature, lower−growth properties. We may create and distribute or sell interests in additional royalty trusts or publicly traded partnerships in the future.

Business Goals. We expect to increase our 2010 production by approximately 10% over 2009 levels. To achieve this target, we plan to drill about 988 (833 net) development wells and perform approximately 865 (720 net) workovers and recompletions in 2010.

We have budgeted $3.37 billion for our 2010 development program, which is expected to be funded by cash flow from operations. An additional $530 million has been budgeted for the construction of pipeline infrastructure and compression and processing facilities that are critical to the transportation and sale of production in several operating regions.

In 2010, given our hedge position and current commodity strip pricing, we expect to generate enough cash flow from operations to fund our $3.9 billion capital budget and to have the ability to reduce debt by more than $500 million.

While we expect to focus primarily on development activities in 2010, as a course of business, we will continue to review acquisition opportunities. If acquisition, development and exploration expenditures exceed cash flow from operations, we expect to obtain additional funding through our bank credit facilities, our commercial paper program, issuance of public or private debt or equity, or asset sales. Strategic property acquisitions may alter the amount budgeted for development and exploration. Our total budget for acquisitions, development and exploration is subject to change to focus on opportunities offering the highest rates of return. We also may reevaluate our budget and drilling programs as a result of significant changes in oil and gas prices. Our ability to achieve production goals depends on the success of our planned drilling programs or property acquisitions made in place of a portion of the drilling program.

Acquisitions

During 2005, we acquired proved properties for a total cost of $1.7 billion. In April 2005, we acquired Antero Resources Corporation, which operated in the Barnett Shale in the Fort Worth Basin. The purchase price was approximately $689 million. In May, we acquired proved properties in East Texas and northwestern Louisiana from Plains Exploration & Production Company for an adjusted purchase price of $336 million. In July 2005, we acquired proved properties in the Permian Basin of West Texas and New Mexico from Exxon Mobil Corporation for an adjusted purchase price of $200 million. Our 2005 acquisitions increased reserves by approximately 803.4 Bcf of natural gas, 2.8 million Bbls of natural gas liquids and 31.1 million Bbls of oil.

During 2006, we acquired proved properties for a total cost of $561 million. In February 2006, we acquired proved and unproved properties in East Texas and Mississippi from Total E&P USA, Inc. for $300 million. Our 2006 acquisitions increased reserves by approximately 157.9 Bcf of natural gas, 4.2 million Bbls of natural gas liquids and 3.3 million Bbls of oil.

During 2007, we acquired proved properties for a total of $3.2 billion. We also acquired $831 million of unproved properties in 2007. In July 2007, we acquired both producing and unproved properties from Dominion Resources, Inc. for $2.5 billion. These properties were located in the Rocky Mountain Region, the San Juan Basin and South Texas. The acquisition was funded by the issuance of 21.6 million shares of our common stock in June 2007 for net proceeds of $1.0 billion, the issuance of $1.25 billion of senior notes in July 2007 and with borrowings under our commercial paper program, which was repaid with a portion of the proceeds from the issuance of $1.0 billion of senior notes in August 2007. After recording an asset retirement obligation of $32 million, other liabilities and transaction costs of $18 million, the purchase price allocated to proved properties was $2.5 billion and unproved properties was $38 million. In October 2007, we announced acquisitions from multiple parties of both producing and unproved properties in the Barnett Shale for approximately $550 million. Our 2007 acquisitions increased reserves by approximately 1.3 Tcf of natural gas, 2.7 million Bbls of natural gas liquids and 11.3 million Bbls of oil.

During 2008, we acquired proved properties for a total of $7.9 billion. We also acquired $3.1 billion of unproved properties in 2008. During the first six months of 2008, we completed acquisitions of both producing and unproved properties for approximately $2.3 billion. These acquisitions included bolt−on acquisitions of additional producing properties, mineral interests and undeveloped leasehold primarily in our Eastern and San Juan Regions and the Barnett, Fayetteville, Woodford and Marcellus Shales. Additionally, in May 2008, we acquired producing properties, leasehold acreage and gathering infrastructure in the Fayetteville Shale from Southwestern Energy Company for approximately $520 million. In July 2008, we acquired producing properties, leasehold acreage and pipeline and gathering infrastructure in the Marcellus Shale in western Pennsylvania and West Virginia from Linn Energy, LLC for approximately $600 million. Also, in July 2008, we acquired producing and undeveloped acreage located in the Bakken Shale in Montana and North Dakota from Headington Oil Company. The total purchase price was $1.8 billion and was funded by cash of $1.05 billion and the issuance of 11.7 million shares of common stock to the sellers valued at $742 million. In September 2008, we acquired Hunt Petroleum Corporation and other associated entities for approximately $4.2 billion, funded by cash of $2.6 billion and the issuance of 23.5 million shares of common stock to the sellers valued at $1.6 billion. Hunt Petroleum owned natural gas and oil producing properties primarily concentrated in our Eastern Region, including East Texas and central and north Louisiana. Additional producing properties, both onshore and offshore, are along the Gulf Coast of Texas, Louisiana, Mississippi and Alabama. Non−operating interests, including producing and undeveloped acreage in the North Sea were also conveyed in the transaction. Including $337 million of debt assumed, $1.1 billion recorded on the step−up of deferred taxes, $168 million recorded for the asset retirement obligation and the assumption of $390 million of other liabilities, the total purchase price plus liabilities assumed was $6.1 billion. This amount was allocated to assets acquired including $4.1 billion to proved properties, $250 million to unproved properties, $1.3 billion to goodwill and $563 million to other assets. In October 2008, we acquired 12,900 acres in the Barnett Shale for approximately $800 million. These acquisitions were funded through the issuance of common stock in February 2008 totaling $1.2 billion and August 2008 totaling $1.4 billion, as well as the issuance of senior notes in April 2008 totaling $2.0 billion and August 2008 totaling $2.2 billion. Additional proceeds were provided by a combination of operating cash flow and borrowings under our commercial paper program and our revolving credit facility. Our 2008 acquisitions increased reserves by approximately 1.5 Tcf of natural gas, 19.9 million Bbls of natural gas liquids and 57.6 million Bbls of oil.

During 2009, we acquired proved properties for a total of $30 million. We also acquired $224 million of unproved properties in 2009. These acquisitions were funded by cash provided by operating activities and are subject to typical post−closing adjustments. Our 2009 acquisitions increased reserves by approximately 22.4 Bcf of natural gas and 0.1 million Bbls of natural gas liquids.

Table of Contents

Significant Properties

The following table summarizes proved reserves and discounted present value, before income tax, of proved reserves by major operating areas at December 31, 2009:

(in millions)	Proved Reserves: Gas (Mcf)	Natural Gas Liquids (Bbls)	Oil (Bbls)	Natural Gas Equivalents (Mcfe)	Discounted Present Value before Income Tax of Proved Reserves *(a)*	
Eastern Region	4,615.9	27.7	23.3	4,921.9	$ 4,286	31%
Mid−Continent and Rocky Mountain Region	2,887.6	—	77.6	3,353.3	2,334	17%
North Texas Region	3,198.0	19.1	0.1	3,313.2	2,150	15%
San Juan Region	1,063.2	37.1	2.1	1,298.4	943	7%
Permian Region	217.3	4.2	172.7	1,278.5	3,166	23%
South Texas and Gulf Coast Region	389.4	5.1	7.8	466.7	705	5%
Other	130.3	—	10.8	195.2	351	2%
Total	12,501.7	93.2	294.4	14,827.2	$ 13,935	100%

(a) We believe that the discounted present value of estimated future net cash flows before income tax is a useful supplemental disclosure to the standardized measure, or after−tax amount, of $10.9 billion. While the standardized measure is dependent on the unique tax situation of each company, the pre−tax discounted amount is based on prices and discount factors that are consistent for all companies. Because of this, the pre− tax discounted amount can be used within the industry and by securities analysts to evaluate estimated future net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the pre−tax discounted amount is the discounted estimated future income tax of $3.1 billion at December 31, 2009.

The following table shows production for the two fields which made up more than 15% of total production for the years ended December 31, 2009, 2008 and 2007:

(in millions)	2009 Freestone Trend	2009 Barnett Shale	2008 Freestone Trend	2008 Barnett Shale	2007 Freestone Trend	2007 Barnett Shale
Total production:						
Gas (Mcf)	217.9	209.9	193.1	170.5	170.7	118.3
Natural gas liquids (Bbls)	—	1.7	—	0.9	—	0.4
Oil (Bbls)	0.3	0.1	0.3	0.1	0.3	0.1
Mcfe	219.7	220.7	195.1	176.5	172.5	121.2

Eastern Region

We began operations in East Texas and northwestern Louisiana in 1998. These properties produce from various formations. Subsequent acquisitions and development activity have significantly increased reserves here since we began operations, including the Hunt Petroleum acquisition in 2008. Approximately 33% of our total proved reserves are in this region. We have expanded our gathering facilities to increase treating capacity to 1.06 Bcf per day. We also operate a gas processing plant in the Cotton Valley Field of Louisiana and significant gas gathering systems and various plants servicing East Texas properties.

Our primary focus in the Eastern Region is in both the Freestone Trend where we have an interest in approximately 370,000 net acres and the Haynesville Shale where we have an interest in approximately 166,000 net acres. The Freestone Trend consists of the Freestone, Bald Prairie, Oaks, Luna, Teague, Dew, Farrar and Bear Grass fields and was our most active gas development area in 2009. Other areas in the region include the Sabine Uplift and Cotton Valley areas of East Texas and northwestern Louisiana.

Mid−Continent and Rocky Mountain Region

Our Mid−Continent and Rocky Mountain Region includes fields in Wyoming, Montana, North Dakota, Kansas, Oklahoma and Arkansas. We have operations in the Anadarko Basin, Fayetteville and Woodford Shales, Fontenelle area, Powder River Basin, Bakken Shale and the Arkoma Basin. During 2010, we will continue to focus our drilling activities in the Fayetteville Shale in Arkansas, the Woodford Shale in Southeast Oklahoma and the Bakken Shale in Montana and North Dakota. A portion of our properties in the Mid−Continent Region are subject to an 80% net profits interest conveyed to the Hugoton Royalty Trust in December 1998.

We operate a gas gathering system in Major County, Oklahoma, a gas gathering system in the Arkansas Fayetteville Shale, a gas plant in Texas County, Oklahoma, and its associated gathering system and a gas plant and associated gathering system in the Bakken Shale area of North Dakota. We also own and operate a gas gathering and water disposal system in the Hartzog Draw area of Wyoming to service our coal bed methane wells.

North Texas Region

Our operations in the Barnett Shale of North Texas began in January 2004 and, with our 2005 acquisition of Antero Resources Corporation and various 2007 and 2008 acquisitions, we are one of the largest producers in the area. We own approximately 266,000 net acres, 60% of which is in the core productive area, and gas gathering and pipeline assets. We also own 410,000 Mcf per day of treating capacity allowing us to add new wells as they are completed.

San Juan Region

Our San Juan Region includes properties in the San Juan and Raton Basins of New Mexico and Colorado, as well as properties in the Uinta Basin of Utah. As a result of the 2007 Dominion acquisition, we significantly expanded our holdings in the Uinta Basin. Production is from conventional as well as coal bed methane sources. We operate a gas gathering system in the Raton and Uinta basins and a gas plant and gas gathering system in Rio Blanco County, Colorado.

Permian Region

The Permian Region is made up of properties in West Texas and southeastern New Mexico. In 2004 and 2005, we significantly expanded our holdings in the area through acquisitions and trades with Chevron, ExxonMobil and others. Our activities on these properties have increased oil production by returning shut−in wells to production, optimizing existing well performance, using fracture stimulation and drilling. We have also experienced successful results in multiple fields including Yates, University Block 9, Goldsmith, Russell, Prentice and Cornell. We operate a carbon dioxide processing plant that primarily serves two operated tertiary flooded oil fields.

South Texas and Gulf Coast Region

The South Texas and Gulf Coast Region includes properties is south Texas, southern Mississippi, Louisiana and Alabama and the Gulf of Mexico. In 2007, we significantly expanded our holdings in South Texas with the Dominion acquisition and, in 2008, we expanded our Gulf Coast holdings and entered into the Gulf of Mexico with the acquisition of Hunt Petroleum Corporation. Most of our properties in the Gulf of Mexico are mature fields located on the shelf. We have experienced successful results in these areas, including the Jeffress, Lopeno, Main Pass and South Marsh Island fields.

Other

The other category includes properties acquired in 2008 in the Appalachia Region and the North Sea. In July 2008, we purchased 152,000 net acres of Marcellus Shale leasehold along with producing properties and a gas gathering system. In September 2008, in the Hunt Petroleum acquisition, we acquired non−operating interests, comprising approximately 160,000 net acres in the North Sea.

Table of Contents

Reserves

The following terms are used in our disclosures of oil and natural gas reserves. For the complete detailed definitions of proved, developed and undeveloped oil and gas reserves applicable to oil and gas registrants, reference is made to Rule 4−10(a) of Regulation S−X of the Securities and Exchange Commission, available at its web site http://www.sec.gov.

Proved reserves—Estimated quantities of crude oil, natural gas and natural gas liquids 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 oil and gas reservoirs under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

Developed reserves—Proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

Undeveloped reserves—Proved reserves which 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 using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Estimated future net revenues—Also referred to herein as “estimated future net cash flows.” Computational result of applying 12−month average prices of oil and gas, based on the first day−of−the−month price for each month in the period, (with consideration of price changes only to the extent provided by existing contractual arrangements) to estimated future production from proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves.

Present value of estimated future net cash flows—The computational result of discounting estimated future net revenues at a rate of 10% annually. The present value of estimated future net cash flows after income tax is also referred to herein as “standardized measure of discounted future net cash flows” or “standardized measure.”

The following are estimated quantities of proved reserves and related cash flows as of December 31, 2009, 2008 and 2007:

(in millions)	December 31 2009	2008	2007
Developed:			
Gas (Mcf)	7,353.1	7,290.3	6,031.5
Natural gas liquids (Bbls)	62.7	52.5	52.9
Oil (Bbls)	212.6	205.0	184.8
Mcfe	9,004.6	8,835.4	7,457.7
Undeveloped:			
Gas (Mcf)	5,148.6	4,512.6	3,409.6
Natural gas liquids (Bbls)	30.5	23.3	13.9
Oil (Bbls)	81.8	62.5	56.4
Mcfe	5,822.6	5,027.0	3,831.3
Total proved:			
Gas (Mcf)	12,501.7	11,802.9	9,441.1
Natural gas liquids (Bbls)	93.2	75.8	66.8
Oil (Bbls)	294.4	267.5	241.2
Mcfe	14,827.2	13,862.4	11,289.0
Estimated future net cash flows:			
Before income tax *(a)*	$ 28,194	$ 34,210	$ 57,949
After income tax	$ 22,669	$ 26,308	$ 39,526
Present value of estimated future net cash flows, discounted at 10%:			
Before income tax *(a)*	$ 13,935	$ 17,165	$ 29,169
After income tax	$ 10,861	$ 12,793	$ 19,538

(a) We believe that the estimated future net cash flows before income tax and the discounted present value of estimated future net cash flows before income tax are useful supplemental disclosures to the after−tax estimated future net cash flows and the standardized measure, or after−tax amount. While the after−tax estimated future net cash flows and the standardized measure are dependent on the unique tax situation of each company, the pre−tax measures are based on prices and discount factors that are consistent for all companies. Because of this, the pre−tax measures can be used within the industry and by securities analysts to evaluate estimated future net cash flows from proved reserves on a more comparable basis. The difference between the after−tax and the pre−tax estimates of future net cash flows is estimated future income tax of $5.5 billion at December 31, 2009, $7.9 billion at December 31, 2008 and $18.4 billion at December 31, 2007. The difference between the standardized measure and the pre−tax discounted amount is the discounted estimated future income tax of $3.1 billion at December 31, 2009, $4.4 billion at December 31, 2008 and $9.6 billion at December 31, 2007.

The process of estimating oil and gas reserves is complex and requires significant judgment as discussed in Item 1A, Risk Factors. As a result, we have developed internal policies and controls for estimating and recording reserves. Our policies regarding booking reserves require proved reserves to be in compliance with the SEC definitions and guidance. Our policies assign responsibilities for compliance in reserves bookings to our reserves engineering group and require that reserve estimates be made by qualified reserves estimators, as defined by the Society of Petroleum Engineers' standards. All qualified reserves estimators are required to receive education covering the fundamentals of SEC proved reserves assignments.

The reserves engineering group is responsible for the internal review of reserve estimates and includes the Senior Vice President—Engineering. The Senior Vice President—Engineering has more than 20 years experience as a reserve engineer. The reserves engineering group is independent of any of our operating areas. The Chief Executive Officer is directly responsible for overseeing the reserves engineering group. No portion of the reserves engineering group's compensation is directly dependent on the quantity of reserves booked.

The reserves engineering group reviews reserve estimates with our third−party petroleum consultants, Miller and Lents, Ltd., an independent petroleum engineering firm. Miller and Lents' primary technical person responsible for calculating our reserves has more than 30 years of experience as a reserve engineer. Miller and Lents prepared the estimates of our proved reserves and the future net cash flows (and related present value) attributable to proved reserves at December 31, 2009, 2008 and 2007. As prescribed by the Securities and Exchange Commission, such proved reserves were estimated using 12−month average oil and gas prices, based on the first−day−of−the−month price for each month in the period, and year end production and development costs for the December 31, 2009 estimate, without escalation. In previous years, such proved reserves were estimated using oil and gas prices and production and development costs as of December 31 of each such year, without escalation. None of our natural gas liquid proved reserves are attributable to gas plant ownership.

Estimated future net cash flows, and the related 10% discounted present value, of year−end 2009 proved reserves are lower than at year−end 2008 because of lower natural gas prices used in estimation of year−end proved reserves partially offset by increased reserves related to development and higher natural gas liquids and oil prices. Average 2009 realized prices used in the estimation of proved reserves were $3.16 per Mcf for gas, $27.18 Bbl for natural gas liquids and $55.96 per Bbl for oil. Year−end 2008 average realized product prices used in the estimation of proved reserves were $4.66 per Mcf for gas, $18.26 per Bbl for natural gas liquids and $38.12 per Bbl for oil. See Note 16 to Consolidated Financial Statements for additional information regarding estimated proved reserves.

Our 2009 development drilling program resulted in the conversion of approximately 16% of our undeveloped reserves into developed reserves during the year. An additional 5% of our undeveloped reserves were removed primarily due to lower gas prices used to estimate the December 31, 2009 reserves. We also added approximately 1.8 Tcfe of new undeveloped reserves. The converted reserves and new undeveloped reserve additions were primarily located in the Eastern Region and the Barnett, Fayetteville, Haynesville, Woodford and Bakken shales. Based on an analysis of our undeveloped reserves, less than 5% have remained classified as undeveloped reserves for more than five years. These undeveloped reserves continue to meet the criteria to qualify as reserves, and are located in areas where we continue to actively drill.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and the interpretation thereof. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices, may justify revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates.

During 2009, we filed estimates of oil and gas reserves as of December 31, 2008 with the U.S. Department of Energy on Form EIA−23 and Form EIA−28. These estimates are consistent with the reserve data reported for the year ended December 31, 2008 in Note 16 to Consolidated Financial Statements, with the exception that Form EIA−23 includes only reserves from properties that we operate.

Exploration and Production Data

For the following data, "gross" refers to the total wells or acres in which we own a working interest and "net" refers to gross wells or acres multiplied by the percentage working interest owned by us. Although many wells produce both oil and gas, a well is categorized as an oil well or a gas well based upon the ratio of oil to gas production.

Table of Contents

Producing Wells

The following table summarizes producing wells as of December 31, 2009, substantially all of which are located in the United States:

	Operated Wells		Nonoperated Wells *(a)*		Total *(b)*	
	Gross	Net	Gross	Net	Gross	Net
Gas	15,526	13,558.8	10,241	1,727.8	25,767	15,286.6
Oil	3,307	2,774.6	5,583	754.6	8,890	3,529.2
Total	18,833	16,333.4	15,824	2,482.4	34,657	18,815.8

(a) Included in the table are 19 gross (1.3 net) nonoperated gas wells located in the North Sea.
(b) 1,063 gross (853.5 net) gas wells and 37 gross (31.0 net) oil wells are dual completions.

Drilling Activity

The following table summarizes the number of wells drilled during the years indicated. As of December 31, 2009, we were in the process of drilling 717 gross (382.6 net) wells. We participated in drilling one gross (0.3 net) exploratory non−productive gas well in the North Sea in 2009. No wells were drilled outside of the United States in 2008 or 2007.

	Year Ended December 31					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Completed as—						
Gas wells	1,815	870.6	1,682	1,069.3	1,275	901.2
Oil wells	261	136.2	218	130.0	269	139.3
Non−productive	36	16.0	15	8.7	12	7.6
Total	2,112	1,022.8	1,915	1,208.0	1,556	1,048.1
Exploratory wells:						
Completed as—						
Gas wells	31	24.7	41	32.0	51	17.4
Oil wells	7	3.2	1	—	1	1.0
Non−productive	12	8.1	9	7.0	9	6.8
Total	50	36.0	51	39.0	61	25.2
Total *(a)*	2,162	1,058.8	1,966	1,247.0	1,617	1,073.3

(a) Included in totals are 1,128 gross (166.2 net) wells in 2009, 717 gross (122.8 net) wells in 2008 and 535 gross (106.0 net) wells in 2007, drilled on nonoperated interests.

Acreage

The following table summarizes developed and undeveloped leasehold acreage in which we own a working interest as of December 31, 2009. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed Acres (a)(b)		Undeveloped Acres	
(in thousands)	Gross	Net	Gross	Net
U.S.				
Texas	1,414	1,027	430	281
Oklahoma	735	446	394	176
New Mexico	698	415	26	21
Arkansas	647	459	290	216
Montana	364	131	192	92
Utah	299	187	123	84
Louisiana	286	155	75	39
North Dakota	240	152	252	191
Kansas	177	160	—	—
West Virginia	150	88	82	58
Pennsylvania	126	98	140	119
Wyoming	105	69	17	13
Colorado	74	49	3	2
Other	98	31	91	76
Total U.S. onshore	5,413	3,467	2,115	1,368
U.S. offshore	268	127	79	45
Total U.S	5,681	3,594	2,194	1,413
North Sea−offshore	350	27	586	133
Grand Total	6,031	3,621	2,780	1,546

(a) Developed acres are acres spaced or assignable to productive wells.

(b) Certain acreage in Oklahoma and Texas is subject to a 75% net profits interest conveyed to the Cross Timbers Royalty Trust, and in Oklahoma, Kansas and Wyoming is subject to an 80% net profits interest conveyed to the Hugoton Royalty Trust.

Most of our undeveloped acreage is subject to lease expiration if initial wells are not drilled within a specified period, generally not exceeding three years. We do not expect to lose any significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future.

Oil and Gas Production, Sales Prices and Production Costs

The following table shows the total and average daily production, the average sales prices per unit of production and the production expense and taxes, transportation and other expense per Mcfe for the indicated periods:

	Year Ended December 31		
	2009	2008	2007
Total production:			
Gas (Mcf)	855,008,071	697,392,186	532,097,846
Natural gas liquids (Bbls)	7,504,580	5,718,295	4,943,781
Oil (Bbls)	24,198,273	20,505,178	17,172,191
Mcfe	1,045,225,189	854,733,024	664,793,678
Average daily production:			
Gas (Mcf)	2,342,488	1,905,443	1,457,802
Natural gas liquids (Bbls)	20,560	15,624	13,545
Oil (Bbls)	66,297	56,025	47,047
Mcfe	2,863,631	2,335,336	1,821,353
Average realized sales prices:			
Gas (per Mcf)	$ 7.13	$ 7.81	$ 7.50
Natural gas liquids (per Bbl)	$ 30.03	$ 48.76	$ 45.37
Oil (per Bbl)	$ 107.65	$ 87.59	$ 70.08
Average realized sales prices before hedging:			
Gas (per Mcf)	$ 3.67	$ 8.04	$ 6.26
Natural gas liquids (per Bbl)	$ 30.03	$ 52.05	$ 45.37
Oil (per Bbl)	$ 57.10	$ 93.17	$ 68.68
Average NYMEX prices:			
Gas (per MMbtu)	$ 3.99	$ 9.03	$ 6.86
Oil (per Bbl)	$ 61.82	$ 99.75	$ 72.39
Production expense (per Mcfe)	$ 0.96	$ 1.10	$ 0.93
Taxes, transportation and other expense (per Mcfe)	$ 0.65	$ 0.82	$ 0.67

Delivery Commitments and Marketing

Our natural gas, crude oil and natural gas liquids production is sold under both long−term and short−term agreements at prices negotiated with third parties. Because our production is sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. Our production is sold to various purchasers, based on their credit rating and the location of our production. For the year ended December 31, 2009, no single purchaser comprised more than 10% of total revenues. We market our gas, as well as some gas produced by third parties, to brokers, local distribution companies and end−users. We have also entered into physical delivery contracts which require us to deliver fixed volumes of gas. We believe our production and reserves are adequate to meet these delivery commitments.

Competition and Markets

We compete with other oil and gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases, marketing of oil and gas, and obtaining goods, services and labor. Some of our competitors have substantially larger financial and other resources. Factors that affect our ability to acquire producing properties include available funds, available information about the property and our standards established for minimum projected return on investment. Gathering systems are the only practical method for the intermediate transportation of natural gas. Therefore, competition for natural gas delivery is presented by other pipelines and gathering systems. Competition is also presented by alternative fuel sources, including heating oil, imported liquefied natural gas and other fossil fuels. Because of the long−lived, high margin nature of our oil and gas reserves and management’s experience and expertise in exploiting these reserves, management believes that it effectively competes in the market.

Federal and State Laws and Regulations

There are numerous federal and state laws and regulations governing the oil and gas industry that are often changed in response to the current political or economic environment. Compliance with existing laws often is difficult and costly and may carry substantial penalties for noncompliance. The following are some specific laws and regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Federal Regulation of Natural Gas

The interstate transportation and certain sales for resale of natural gas, including transportation and storage rates charged, tariffs and various other matters, are subject to federal regulation by the Federal Energy Regulatory Commission.

Federal wellhead price controls on all domestic gas were terminated on January 1, 1993, and none of our gathering systems are currently subject to FERC regulation. While natural gas prices currently are unregulated, Congress historically has been active in the area of natural gas regulation. It is impossible to predict whether new legislation to regulate natural gas or natural gas drilling techniques (e.g., hydraulic fracturing) might be proposed, what proposals, if any, might actually be enacted, and what effect, if any, such proposals might have on our natural gas sales or production.

On August 8, 2005, Congress enacted the Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, to direct FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce, and to significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder. FERC has promulgated regulations to implement the Energy Policy Act. We cannot predict the impact of future government regulation on any natural gas facilities, sales or transportation transactions.

Although FERC’s regulations should generally facilitate the transportation of gas produced from our properties and the direct access to end−user markets, the future impact of these regulations on marketing our production or on our gas transportation business cannot be predicted. We, however, do not believe that we will be affected differently than competing producers and marketers.

Federal Regulation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The net price received from the sale of these products is affected by market transportation costs. A significant part of our oil production is transported by pipeline. Under rules adopted by FERC effective January 1995, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. These rules have had little effect on our oil transportation cost.

In December 2007, the President signed into law the Energy Independence & Security Act of 2007 (PL 110−140). The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline, or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations, and establishes penalties for violations thereunder. We cannot predict the impact of future government regulation on any natural gas facilities.

State Regulation

Oil and gas operations are subject to various types of regulation at the state and local levels. Such regulation includes requirements for drilling permits, the method of developing new fields, the spacing and operation of wells, air quality concerns and waste prevention. The production rate may be regulated and the maximum daily production allowable from oil and gas wells may be established on a market demand or conservation basis. These regulations may limit production by well and the number of wells that can be drilled. In addition, some states have adopted regulation or are considering regulations that are designed to protect water supplies, and we cannot predict the effect of the regulations that have been adopted or whether these regulations will be adopted or, if adopted, the effect these rules may have on our operations.

We may become a party to agreements relating to the construction or operations of pipeline systems for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the state's administrative authority charged with regulating pipelines. The rates that can be charged for gas, the transportation of gas, and the construction and operation of such pipelines would be subject to the regulations governing such matters. Two of our gathering subsidiaries are designated gas utilities and are subject to such state regulations. Certain states have recently adopted regulations with respect to gathering systems, and other states are considering similar regulations. New regulations have not had a material effect on the operations of our gathering systems, but we cannot predict whether any further rules will be adopted or, if adopted, the effect these rules may have on our gathering systems.

Federal, State or Native American Leases

Our operations on federal, state or Native American oil and gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on−site security regulations and other permits and authorizations issued by the Bureau of Land Management, Minerals Management Service and other agencies.

Environmental Regulations

Various federal, state and local laws relating to protection of the environment directly impact oil and gas exploration, development and production operations, and consequently may impact our operations and costs. These laws and regulations govern, among other things, emissions to the atmosphere, discharges of pollutants into waters of the United States, underground injection of waste water, the generation, storage, transportation and disposal of waste materials, and protection of public health, natural resources and wildlife. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas. In some jurisdictions, the laws and regulations are constantly being revised, creating the potential for delays in development plans.

Although we have used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released onto or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, petroleum hydrocarbons or wastes may have been disposed of or released by prior operators of properties we are acquiring as well as by current third party operators of properties in which we have an ownership interest. Properties impacted by any such disposal or releases could be subject to costly and stringent investigatory or remedial requirements under environmental laws, some of which impose strict, joint and several liability without regard to fault or the legality of the original conduct, including the Comprehensive Environmental Response, Compensation, and Liability Act, also known as "CERCLA" or the "Superfund" law and analogous state laws.

We are committed to environmental protection and believe we are in substantial compliance with applicable environmental laws and regulations. We routinely obtain permits for our facilities and operations in accordance with the applicable laws and regulations. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations. We have made and will continue to make expenditures in our efforts to comply with environmental regulations and requirements. These costs are considered a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with government regulations.

We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our financial position or operations. However, due to continuing changes in these laws and regulations and judicial construction of same, we are unable to predict with any reasonable degree of certainty our future costs of complying with these governmental requirements. We have been able to plan for and comply with new initiatives without materially changing our operating strategies.

There is an increased focus by local, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change. Various regulatory bodies have announced their intent to regulate GHG emissions. As these regulations are under development, we are unable to predict the total impact of the potential regulations upon our business, and it is possible that we could face increases in operating costs in order to comply with GHG emissions legislation. We are reviewing, through our Climate Change Committee, issues involving GHG emissions, including assisting management in monitoring the science of climate change and making recommendations to help develop emission reduction programs. In 2009, we published our calendar year 2008 GHG emissions estimates.

We maintain levels of insurance customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, produced water or other substances. We are not fully insured against all environmental risks, and no coverage is maintained with respect to any penalty or fine required to be paid by us.

Future Laws and Regulations

The oil and gas industry is highly regulated and, from time to time, Congress and state legislatures consider broad and sweeping policy changes that may affect the industry. We cannot predict the impact of such future legislative or regulatory initiatives.

Employees

We had 3,335 employees as of December 31, 2009. We consider our relations with our employees to be good.

Executive Officers of the Company

The executive officers of the Company are elected by and serve until their successors are elected by the Board of Directors.

Bob R. Simpson, 61, was a founder of the Company and has been Chairman of the Board since July 1, 1996. Mr. Simpson served as Chief Executive Officer of the Company from 1986 to December 2008. Mr. Simpson was Vice President of Finance and Corporate Development (1979−1986) and Tax Manager (1976−1979) of Southland Royalty Company.

Keith A. Hutton, 51, has been Chief Executive Officer since December 1, 2008. Prior thereto, Mr. Hutton served as President, Executive Vice President−Operations or held similar positions with the Company since 1987. From 1982 to 1987, Mr. Hutton was a Reservoir Engineer with Sun Exploration & Production Company.

Vaughn O. Vennerberg II, 55, has been President since December 1, 2008. Prior thereto, Mr. Vennerberg served as Senior Executive Vice President and Chief of Staff, Executive Vice President−Administration or held similar positions with the Company since 1987. Prior to that time, Mr. Vennerberg was employed by Cotton Petroleum Corporation and Texaco Inc. (1979−1986).

Louis G. Baldwin, 60, has been Executive Vice President and Chief Financial Officer or held similar positions with the Company since 1986. Mr. Baldwin was Assistant Treasurer (1979−1986) and Financial Analyst (1976−1979) at Southland Royalty Company.

Timothy L. Petrus, 55, has been Executive Vice President−Acquisitions since May 1, 2005. Prior thereto, Mr. Petrus served as Senior Vice President−Acquisitions or held similar positions with the Company since 1988. Prior to that time, Mr. Petrus was employed by Texas American Bank and Exxon Corporation.

Bennie G. Kniffen, 59, has been Senior Vice President and Controller or held similar positions with the Company since 1986. From 1976 to 1986, Mr. Kniffen held the position of Director of Auditing or similar positions with Southland Royalty Company.

Gary D. Simpson, 46, has been Senior Vice President, Investor Relations and Finance or held similar positions with the Company since 1999. Prior to that time, Mr. Simpson was an Operations Engineer with Arco International Oil & Gas. In May 2008, Mr. Simpson was appointed to serve as an advisory director.

Item 1A. *RISK FACTORS*

The following factors, among others, could cause actual results to differ materially from those contained in forward−looking statements made in this report and presented elsewhere by management from time to time. Such factors, among others, may have a material adverse effect upon our business, financial condition, and results of operations.

The following discussion of our risk factors should be read in conjunction with the consolidated financial statements and related notes included herein. Because of these and other factors, past financial performance should not be considered an indication of future performance.

Oil, natural gas and natural gas liquids prices fluctuate due to a number of uncontrollable factors, and any decline will adversely affect our financial condition.

Our results of operations depend upon the prices we receive for our natural gas, oil and natural gas liquids. We sell most of our natural gas, oil and natural gas liquids at current market prices rather than through fixed−price contracts. Historically, the markets for natural gas, oil and natural gas liquids have been volatile and are likely to remain volatile in the future. The prices we receive depend upon factors beyond our control, which include:

- weather conditions;
- political instability or armed conflict in oil−producing regions, such as current conditions in the Middle East, Nigeria and Venezuela;
- the supply of domestic and foreign oil, natural gas and natural gas liquids;
- the ability of members of the Organization of Petroleum Exporting Countries to agree upon and maintain oil prices and production levels;
- the level of consumer demand;
- worldwide economic conditions;
- the price and availability of alternative fuels;
- domestic and foreign governmental regulations and taxes;
- the proximity to and capacity of transportation facilities; and
- the effect of worldwide energy conservation measures.

Government regulations, such as regulations of natural gas transportation and price controls, can affect product prices in the long term. These external factors and the volatile nature of the energy markets make it difficult to reliably estimate future prices of oil and natural gas.

To the extent we have not hedged our production, any decline in natural gas and oil prices adversely affects our financial condition. If the oil and gas industry experiences significant price declines, we may, among other things, be unable to meet our financial obligations or make planned capital expenditures.

Our use of hedging arrangements could result in financial losses or reduce our income.

To reduce our exposure to fluctuations in natural gas, oil and natural gas liquids prices, we have entered into and expect in the future to enter into hedging arrangements for a portion of our natural gas, oil and natural gas liquids production. However, we may not be able to hedge our future production at prices we deem attractive. These hedging arrangements expose us to risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counterparty to the hedging contract defaults on its contractual obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in natural gas, oil and natural gas liquids prices.

We have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms.

We make, and will continue to make, substantial capital expenditures for the acquisition, development, exploration and abandonment of our oil and natural gas reserves. We intend to finance our capital expenditures primarily through cash flow from operations, bank and commercial paper borrowings and public and private equity and debt offerings. Lower oil and natural gas prices, however, would reduce our cash flow and could affect our access to the capital markets. Costs of exploration and development were $3.0 billion in 2009, $3.9 billion in 2008 and $2.8 billion in 2007. During 2009, we spent $30 million on proved property acquisitions and $224 million on unproved property acquisitions. Our exploration and development budget for 2010 is $3.37 billion. An additional $530 million has been budgeted for the construction of pipeline infrastructure and compression and processing facilities in 2010.

We believe that, after debt service, we will have sufficient cash from operating activities to finance our exploration and development expenses through 2010. If revenues decrease, however, and we are unable to obtain additional debt or equity financing, we may lack the capital necessary to replace our reserves or to maintain production at current levels.

A financial crisis may impact our business and financial condition in ways that we cannot predict.

The continued uncertainties in the global financial system may continue to have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. We believe that our development and exploration budget allows us to fund our business with anticipated internally generated cash flow. However, if we were to need to access the capital markets, as a result of this crisis we may not have the ability to raise capital. Also, if the current economic conditions do not improve, it is possible that we could have additional receivables become uncollectible and counterparties under our hedging could be unable to perform their obligations or seek bankruptcy protection. Additionally, a worsening economic situation could lead to further reductions in demand for natural gas and oil, or lower prices for natural gas and oil, or both, which could have a negative impact on our revenues.

We have substantial indebtedness and may incur substantially more debt. Any failure to meet our debt obligations would adversely affect our business and financial condition.

We have incurred substantial debt. As a result of our indebtedness, we will need to use a portion of our cash flow to pay principal and interest, which will reduce the amount available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our bank revolving credit, term loans and commercial paper indebtedness is at a variable interest rate, so a rise in interest rates will generate greater interest expense to the extent we do not have interest rate protection hedges. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

Together with our subsidiaries, we may incur substantially more debt in the future. The indentures governing our outstanding public debt do not contain restrictions on our incurrence of additional indebtedness. To the extent new debt is added to our current debt levels, the risks resulting from indebtedness could substantially increase. Also, if we repurchase or repay any of our term loans or public debt, we cannot re−borrow these funds and may not be able to enter into a new debt arrangement with similar terms or rates.

Our access to the commercial paper market is predicated on continued acceptable short−term ratings by Standard & Poors and Moody’s. Any downgrade in those ratings may impact our borrowing costs as well as our access to the commercial paper market. Additionally, any downgrade to our long−term ratings could increase our borrowing costs and limit our access to capital markets.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance the debt, sell assets or sell shares of common stock on terms that we do not find attractive if it can be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under the indebtedness, which could adversely affect our business, financial condition and results of operations.

Competition in the oil and natural gas industry is intense, and some of our competitors have greater financial, technological and other resources than we have.

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation, exploration and production. The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. We face intense competition from independent, technology−driven companies as well as from both major and other independent oil and natural gas companies in each of the following areas:

- seeking to acquire desirable producing properties or new leases for future exploration;
- marketing our oil and natural gas production;
- integrating new technologies;
- seeking to acquire the equipment and expertise necessary to develop and operate our properties; and
- hiring qualified people.

Some of our competitors have financial, technological and other resources substantially greater than ours, and some of them are fully integrated oil companies. These companies may be able to pay more for development prospects and productive oil and natural gas 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. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

The failure to replace our reserves could adversely affect our financial condition.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves generally decline when oil and natural gas are produced unless we continue to conduct successful exploitation, development or exploration activities or acquire properties containing proved reserves, or both. We may not be able to economically find, develop or acquire additional reserves. Furthermore, while our revenues may increase if oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions or changes in conditions could cause the quantities and net present value of our reserves to be overstated.

To prepare estimates of economically recoverable oil and natural gas reserves and future net cash flows, we analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We also analyze available geologic, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs. Actual results most likely will vary from our estimates. Any significant variance could reduce the estimated quantities and present value of reserves shown in this annual report.

One should not assume that the present value of future net cash flows from our proved reserves shown in this annual report is the current market value of our estimated oil and natural gas reserves. In accordance with Securities and Exchange Commission requirements, we base the estimated discounted future net cash flows from our proved reserves on prices based on a 12−month average price, using the first−day−of−the−month price for each month in the period, and year end costs. Prior to 2009, we used year end oil and gas prices and costs to estimate our discounted future net cash flows from our proved reserves. Actual current and future prices and costs may differ materially from those used in the net present value estimate, and as a result, net present value estimates using current prices and costs may be significantly less than the estimate which is provided in this annual report.

Producing and unproved property acquisitions are a component of our growth strategy, and our failure to complete future acquisitions successfully could reduce our earnings and slow our growth.

Our business strategy has emphasized growth through acquisitions, but we may not be able to continue to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our growth strategy may be hindered if we are not able to obtain financing or regulatory approvals. Our ability to grow through acquisitions and manage growth will require us to continue to invest in operational, financial and management information systems and to attract, retain, motivate and effectively manage our employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether significant acquisitions are completed in particular periods.

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities.

Our recent growth is due in part to acquisitions of both producing and unproved properties, and we expect acquisitions will continue to contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, exploration and development potential, lease terms, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties, which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not allow us to become sufficiently familiar with the properties, and we do not always discover structural, subsurface and environmental problems that may exist or arise. Our review prior to signing a definitive purchase agreement may be even more limited.

We generally are not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities, on acquisitions. Normally, we acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. If material breaches are discovered by us prior to closing, we could require adjustments to the purchase price, or, if the claims are significant, we or the seller may have a right to terminate the agreement. We could also fail to discover breaches or defects prior to closing and incur significant unknown liabilities, including environmental liabilities, or experience losses due to title defects, for which we would have limited or no contractual remedies or insurance coverage.

There are risks in acquiring both producing and unproved properties, including difficulties in integrating acquired properties into our business, additional liabilities and expenses associated with acquired properties, diversion of management attention, and costs of increased scope, geographic diversity and complexity of our operations.

Increasing our reserve base through acquisitions is an important part of our business strategy. Our failure to integrate acquired businesses successfully into our existing business, or the expense incurred in consummating future acquisitions, could result in our incurring unanticipated expenses and losses. In addition, we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

In connection with future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations.

Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expenses, all of which could have a material adverse effect on our financial condition and operating results.

Our development and exploratory drilling efforts and our operations of our wells may not be profitable or achieve our targeted returns.

We acquire significant amounts of unproved property in order to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire both producing and unproved properties as well as lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells. Drilling for natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for natural gas and crude oil, costs associated with producing natural gas and oil and our ability to add reserves at an acceptable cost. We rely to a significant extent on seismic data and other advanced technologies in identifying unproved property prospects and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of unproved property or drilling a well, whether natural gas or oil is present or may be produced economically. The use of seismic data and other technologies also requires greater pre−drilling expenditures than traditional drilling strategies.

Drilling oil and natural gas wells is a high−risk activity and subjects us to a variety of factors that we cannot control.

Drilling oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive oil and natural gas reservoirs. We may not recover all or any portion of our investment in new wells. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause our drilling activities to be unsuccessful and result in a total loss of our investment. In addition, we often are uncertain as to the future cost or timing of drilling, completing and operating wells. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions, including urban drilling;
- title problems;
- restricted access to land for drilling or laying pipeline;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, including hurricanes in the Gulf of Mexico; and
- costs of, or shortages or delays in the availability of, drilling rigs, tubular materials and equipment.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control.

The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities, as well as any delays in constructing new infrastructure facilities, could harm our business. We deliver oil and natural gas through gathering systems and pipelines that we do not own. These facilities may be temporarily unavailable due to market conditions or mechanical reasons, or may not be available to us in the future.

We are subject to complex federal, state, local and foreign laws and regulations that could adversely affect our business.

Extensive federal, state, local and foreign regulation of the oil and gas industry significantly affects our operations. In particular, our oil and natural gas exploration, development and production, and our storage and transportation of liquid hydrocarbons, are subject to stringent environmental regulations. These regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning oil and natural gas wells and other related facilities. These regulations may become more demanding in the future. Matters subject to regulation include:

- discharge permits for drilling operations;
- drilling bonds;
- spacing of wells;

- unitization and pooling of properties;
- environmental protection;
- greenhouse gas emissions;
- drilling techniques, including hydraulic fracturing;
- reports concerning operations; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property damage;
- oil spills;
- discharge of hazardous materials;
- reclamation costs;
- remediation and clean−up costs; and
- other environmental damages.

Although we believe that our operations generally comply with applicable laws and regulations, failure to comply could result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Further, these laws and regulations could change in ways that substantially increase our costs. Any of these liabilities, penalties, suspensions, terminations or regulatory changes could make it more expensive for us to conduct our business or cause us to limit or curtail some of our operations.

We currently own, lease or expect to acquire, and have in the past owned or leased, numerous properties that have been used for the exploration and production of oil and natural gas for many years. Although we have used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed or released on or under the properties owned or leased by us or on or under other locations where such wastes were taken for disposal. In addition, petroleum hydrocarbons or wastes may have been disposed or released by prior operators of properties that we are acquiring as well as by current third party operators of properties in which we have an ownership interest. Properties impacted by any such disposal or release could be subject to costly and stringent investigatory or remedial requirements under environmental laws, some of which impose strict joint and several liability without regard to fault or the legality of the original conduct. These laws include the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as “CERCLA” or the “Superfund” law, the federal Resource Conservation and Recovery Act and analogous state laws. Under these laws and any implementing regulations, we could be required to remediate contaminated properties and take actions to compensate for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damages allegedly caused by the release of petroleum hydrocarbons or wastes into the environment. We currently do not expect any remedial obligations imposed under environmental laws to have a significant effect on our operations.

Our operations in U.S. waters are subject to the federal Oil Pollution Act, which imposes a variety of requirements related to the prevention of oil spills and liability for damages resulting from such spills. The Oil Pollution Act imposes strict joint and several liability on responsible parties for oil removal costs and a variety of public and private damages, including natural resource damages. Liability limits for offshore facilities require a responsible party to pay all removal costs, plus up to $75 million in other damages. These liability limits do not apply, however, if the spill was caused by gross negligence or willful misconduct of the party, if the spill resulted from violation of a federal safety, construction or operation regulation, or if the party failed to report the spill or cooperate fully in any resulting cleanup. The Oil Pollution Act also requires a responsible party at an offshore facility to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We believe that our operations are in substantial compliance with Oil Pollution Act requirements.

The Department of Transportation, through the Office of Pipeline Safety and Research and Special Programs Administration, has implemented a series of rules requiring operators of natural gas and hazardous liquid pipelines to develop integrity management plans for pipelines that, in the event of a failure, could impact certain high consequence areas. These rules also require operators to conduct baseline integrity assessments of all applicable pipeline segments located in the high consequence areas. We are currently in the process of identifying all of our pipeline segments that may be subject to these rules and are developing integrity management plans for all covered pipeline segments. We do not expect to incur significant costs in achieving compliance with these rules.

Our business involves many operating risks that may result in substantial losses, and insurance may be unavailable or inadequate to protect us against these risks.

Our operations are subject to hazards and risks inherent in drilling for, producing and transporting oil and natural gas, such as:

- fires;
- natural disasters;
- explosions;
- pressure forcing oil or natural gas out of the wellbore at a dangerous velocity coupled with the potential for fire or explosion;
- weather, including hurricanes in the Gulf of Mexico;
- failure of oilfield drilling and service tools;
- changes in underground pressure in a formation that causes the surface to collapse or crater;
- pipeline ruptures or cement failures; and
- environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases.

Any of these risks can cause substantial losses resulting from:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We do not insure against the loss of oil or natural gas reserves as a result of operating hazards or insure against business interruption. Losses could occur from uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operations.

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

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scope, and the United States and others instituted military action in response. These conditions caused instability in world financial markets and generated global economic instability. The continued threat of terrorism and the impact of military and other action, including U.S. military operations in Afghanistan and Iraq, will likely lead to continued volatility in crude oil and natural gas prices and could affect the markets for our operations. In addition, 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 risks and, depending on their ultimate magnitude, could have a material adverse effect on our business.

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. 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 for their operation. 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 or lead to unexpected future costs.

Failure to complete the proposed merger with ExxonMobil could negatively impact our stock price and our future business and financial results.

On December 13, 2009, we entered into a definitive merger agreement with Exxon Mobil Corporation under which we would become a wholly owned subsidiary of ExxonMobil. As a result of the merger, each outstanding share of our common stock will be converted into 0.7098 shares of ExxonMobil common stock. If the merger is not completed, our ongoing business may be adversely affected and, without realizing any of the benefits of having completed the merger, we would be subject to a number of risks, including the following:

- we may experience negative reactions from the financial markets and our customers and employees;
- we may be required to pay ExxonMobil a termination fee of $900 million if the merger is terminated under certain circumstances;
- we will be required to pay certain costs relating to the merger, whether or not the merger is completed;
- the merger agreement places certain restrictions on the conduct of our business prior to the completion of the merger or the termination of the merger agreement. Such restrictions, the waiver of which is subject to the consent of ExxonMobil (not to be unreasonably withheld, conditioned or delayed), may prevent us from making certain acquisitions or taking certain other specified actions during the pendency of the merger; and
- matters relating to the merger (including integration planning) may require substantial commitments of time and resources by our management, which would otherwise have been devoted to other opportunities that may have been beneficial to us as an independent company.

There can be no assurance that the risks described above will not materialize, and if any of them do, they may adversely affect our business, financial results and stock price.

The merger with ExxonMobil may cause disruption in our business and present difficulties attracting, motivating and retaining executives and other key employees in light of the merger.

Parties with which we do business may experience uncertainty associated with the merger, including with respect to current or future business relationships. These disruptions could have an adverse effect on our business, financial condition, results of operations or prospects. The adverse effect of such disruptions could be exacerbated by a delay in the completion of the merger or termination of the merger agreement. In addition, uncertainty about the effect of the merger on our employees may have an adverse effect on us. This uncertainty may impair our ability to attract, retain and motivate key personnel until the merger is completed. Employee retention may be particularly challenging during the pendency of the merger, as employees may experience uncertainty about their future roles with ExxonMobil.

Table of Contents

The merger agreement with ExxonMobil limits our ability to pursue alternatives to the merger.

The merger agreement contains provisions that make it more difficult for us to sell the business to a party other than ExxonMobil. These provisions include a general prohibition on us or any of our employees soliciting any acquisition proposal or offer for a competing transaction, the requirement that we pay a termination fee of $900 million in the aggregate if the merger agreement is terminated in specified circumstances and the requirement that we submit the adoption of the merger agreement to a vote of our stockholders even if our board of directors changes its recommendation in favor of the adoption of the merger agreement in a manner adverse to ExxonMobil. While we believe these provisions are reasonable and not preclusive of other offers, the provisions might discourage a third party that has an interest in acquiring all of or a significant part of our business from considering or proposing that acquisition, even if that party were prepared to pay consideration with a higher per−share market price than the currently proposed merger consideration. Furthermore, the termination fee may result in a potential competing acquirer proposing to pay a lower per−share price to acquire us than it might otherwise have proposed to pay because of the added expense of the $900 million termination fee that may become payable in certain circumstances.

Item 1B. *UNRESOLVED STAFF COMMENTS*

As of December 31, 2009, we do not have any Securities and Exchange Commission staff comments that have been unresolved for more than 180 days.

Item 3. *LEGAL PROCEEDINGS*

In July 2005 a predecessor company that we acquired, Antero Resources Corporation, was served with a lawsuit styled *Threshold Development Company, et al. v. Antero Resources Corp*., which lawsuit was filed in the District Court of Wise County, Texas. The plaintiffs are surface owners, royalty owners and prior working interest owners in several oil and gas leases as well as parties to other contractual agreements under which Antero Resources Corporation owned an interest. Antero Resources Corporation, the defendant, was acquired by us on April 1, 2005. The claims related to alleged events pre−dating the acquisition and concern non−payment of royalties, improper calculation of royalties, improper pricing related to royalties, trespass, failure to develop and breach of contract. We settled all claims related to the payment of royalties and trespass. Under the remaining claims, the plaintiffs sought both damages and termination of the existing oil and gas leases covering their interests. In October 2008, the trial court granted our motion for summary judgment, resulting in the dismissal of the plaintiffs' remaining claims. The plaintiffs have appealed the court's judgment. Based on a review of the current facts and circumstances with counsel, management has provided for what is believed to be a reasonable estimate of the loss exposure for this matter. While acknowledging the uncertainties of litigation, management believes that the ultimate outcome of this matter will not have a material effect on our earnings, cash flows or financial position.

In November 2008, an action was filed against the Company and our directors styled *Freedman v. Adams, et al*. in the Delaware Court of Chancery. The plaintiff is alleged to be a stockholder and brings the suit as a derivative action on behalf of the Company. The plaintiff seeks an equitable accounting for the alleged losses by the Company and injunctions mandating that a Section 162(m) plan be submitted to our stockholders for their approval and against further non−deductible payments, along with an award of accountants', experts' and attorneys' fees. We have filed a motion to dismiss. While we did not have in place a Section 162(m) plan at the time the suit was filed for cash payments, the Board of Directors approved a Section 162(m) plan in February 2009 that was approved by our stockholders at our annual meeting in May 2009. Although we are unable to predict the final outcome of this case, we believe that the allegations of this lawsuit are without merit, and we intend to vigorously defend the action.

In September 2008, a class action lawsuit was filed against the Company styled *Wallace B. Roderick Revocable Living Trust, et al. v. XTO Energy Inc.* in the District Court of Kearny County, Kansas. We removed the case to federal court in Wichita, Kansas. The plaintiffs allege that we have improperly taken post−production costs from royalties paid to the plaintiffs from wells located in Kansas, Oklahoma, and Colorado. The plaintiffs also seek to represent all royalty owners in these three states as a class. We have answered, denying all claims, and have filed motions to dismiss a portion of the claims. The federal court recently granted our motion for summary judgment concerning prior settled class actions that overlap plaintiff's proposed class action. The court also granted our motion to dismiss those portions of plaintiff's class that are currently being prosecuted in another case. Based on a review of the current facts and circumstances with counsel, management has provided for what is believed to be a reasonable estimate of the loss exposure for this matter. While acknowledging the uncertainties of litigation, management believes that the ultimate outcome of this matter will not have a material effect on our earnings, cash flows or financial position.

On December 14, 2009, Exxon Mobil Corporation and XTO Energy announced that the companies had entered into a definitive agreement under which we would become a wholly owned subsidiary of ExxonMobil. As a result of this announcement, a number of putative shareholder class actions have been filed, alleging breaches of fiduciary duties by the individual members or our Board of Directors. Each lawsuit generally seeks, among other things, declaratory and injunctive relief concerning the alleged fiduciary breaches, injunctive relief prohibiting the defendants from consummating the merger, imposition of constructive trusts in favor of plaintiffs and putative class members and unspecified monetary damages. Several putative shareholders have also filed an individual lawsuit in federal court alleging violations of the federal securities laws based on alleged false and material misrepresentations or omissions in the preliminary proxy filed with the Securities and Exchange Commission in connection with the proposed merger. The federal individual action also seeks to enjoin the proposed merger.

Two putative shareholder class actions were filed in the Delaware Court of Chancery between December 17, 2009 and December 18, 2009. Those cases are styled as (i) *Teamsters Allied Benefit Funds, et al. v. XTO Energy Inc., et al., Case No. 5150, filed on December 17, 2009* and (ii) *Nicholas Lombardi v. XTO Energy Inc., et al., Case No. 5152, filed on December 18, 2009.* On December 22, 2009, the Delaware Court of Chancery entered an order consolidating the complaints filed as of that date under the caption *In re XTO Energy Inc. Shareholders Litigation*.

Eleven putative shareholder class actions were filed in the District Courts of Tarrant County, Texas between December 14, 2009, and January 6, 2010. Those cases are styled: (i) *Mary Pappas, et al. v. XTO Energy Inc., et al.*, No. 342−242403−09, filed on December 14, 2009; (ii) *Sanjay Israni, et al. v. XTO Energy Inc., et al.*, No. 017−242424−09, filed on December 15, 2009; (iii) *Michael Walsh, et al. v. XTO Energy Inc., et al.*, No. 153−242432−09, filed on December 15, 2009; (iv) *Ronald Gross, et al. v. XTO Energy Inc., et al.*, No. 141−242460−09, filed on December 16, 2009; (v) *Jeffrey Fink, et al. v. Bob R. Simpson, et al.*, No. 048−242500−09, filed on December 17, 2009; (vi) *Lawrence Treppel, et al. v. XTO Energy Inc., et al.*, No. 342−242523−09, filed on December 18, 2009; (vii) *Nicholas Weil, et al. v. XTO Energy Inc., et al.*, No. 096−242526−09, filed on December 18, 2009; (viii) *Charles Kreps, et al. v. XTO Energy Inc., et al.*, Case No. 352−242548−09, filed on December 21, 2009; (ix) *Murray Silver, et al. v. XTO Energy Inc., et al.*, No. 342−242630−09, filed on December 22, 2009; (x) *William Stratton, et al. v. XTO Energy Inc., et al.*, No. 096−242775−09, filed on December 30, 2009; and (xi) *United Food and Commercial Workers Union Local 880−Retail Food Employers Joint Pension Fund v. XTO Energy Inc., et al.*, No. 342−242849−10, filed on January 6, 2010. On January 12, 2010, the court entered orders consolidating the eleven cases filed as of that date under the caption *In re XTO Energy Shareholder Class Action Litigation*.

Two putative shareholder class actions were filed in the United States District Court for the Northern District of Texas between December 28, 2009 and January 5, 2010. Those cases are styled (i) *James Harrison, et al. v. XTO Energy Inc., et al.*, No. 4:09−cv−768, filed on December 28, 2009 and (ii) *Walt Schumann, et al. v. XTO Energy Inc., et al.*, No. 4:10−cv−007, filed on January 5, 2010. On February 5, 2010, the plaintiffs in the two federal actions filed an unopposed motion to consolidate the cases.

Several putative shareholders filed an individual action in the United States District Court for the Northern District of Texas on February 11, 2010 alleging violations of the federal securities laws based on alleged false and material misrepresentations or omissions in the preliminary proxy filed with the Securities and Exchange Commission in connection with the proposed merger. That case is styled *Mary Pappas, et al. v. Bob R. Simpson, et al.*, No. 4:10−cv−00094−A, filed February 11, 2010.

We believe that all of the putative shareholder lawsuits are without merit and intend to vigorously defend against such claims.

We are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. Our management and legal counsel do not believe that the ultimate resolution of these claims, including the lawsuits described above, will have a material effect on our financial position or liquidity, although an unfavorable outcome could have a material adverse effect on the operations of a given interim period or year.

Item 4. ***SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS***

There were no matters submitted to a vote of security holders during the fourth quarter of 2009.

PART II

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

Our common stock is listed on the New York Stock Exchange and trades under the symbol "XTO." On December 13, 2009, we entered into a definitive merger agreement with Exxon Mobil Corporation under which we would become a wholly owned subsidiary of ExxonMobil. As a result of the merger, each outstanding share of our common stock will be converted into 0.7098 shares of ExxonMobil common stock. Completion of the merger remains subject to certain conditions, including the adoption of the merger agreement by our stockholders, as well as certain governmental and regulatory approvals. We currently expect to complete the merger in the second quarter of 2010, however, no assurance can be given as to when, or if, the merger will occur.

The following table sets forth quarterly high and low closing prices and cash dividends declared for each quarter of 2009 and 2008:

	High	Low	Cash Dividend
2009			
First Quarter	$39.92	$29.19	$ 0.125
Second Quarter	44.27	31.50	0.125
Third Quarter	42.91	33.88	0.125
Fourth Quarter	47.86	38.96	0.125
2008			
First Quarter	$63.13	$48.73	$ 0.120
Second Quarter	73.40	61.18	0.120
Third Quarter	69.16	43.54	0.120
Fourth Quarter	45.69	26.71	0.120

The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the Board of Directors and will depend on our financial condition, earnings and cash flow from operations, the level of our capital expenditures, our future business prospects and other matters the Board of Directors deems relevant. In addition, under the terms of the merger agreement with ExxonMobil, during the period before the closing of the merger, we are prohibited from declaring, setting aside or paying any dividend or other distribution except for our regular quarterly cash dividend, which is not to exceed $0.125 per share. The merger agreement also provides that we will coordinate the declaration of dividends with ExxonMobil before the completion of the merger so that both our shareholders and the shareholders of ExxonMobil only receive, in any quarter, one dividend from each company.

On February 16, 2010, the Board of Directors declared a quarterly dividend of $0.125 per common share, payable on April 15, 2010 to stockholders of record on March 31, 2010. On February 19, 2010, we had 2,294 stockholders of record.

Table of Contents

The following summarizes purchases of our common stock during fourth quarter 2009:

Month	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs *(1)*	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October	21,882	$ 44.34	—	
November	246,699	$ 42.36	—	
December	1,710,005	$ 46.54	—	
Total	1,978,586*(2)*	$ 46.00	—	22,208,000

(1) The Company has a repurchase program approved by the Board of Directors in August 2004 for the repurchase of up to 25 million shares of the Company's common stock.

(2) Does not include performance or restricted share forfeitures. Includes 1,459,753 shares of common stock delivered or attested to in satisfaction of the exercise price upon the exercise of employee stock options under both the 1998 and 2004 Stock Incentive Plans. Also includes 518,833 shares of common stock purchased during the quarter from employees in connection with the settlement of income tax withholding obligations upon vesting of restricted shares and performance shares under the 2004 Stock Incentive Plan. These share purchases were not part of a publicly announced program to purchase common shares.

Item 6. *SELECTED FINANCIAL DATA*

The following table shows selected financial information for each of the years in the five−year period ended December 31, 2009. Significant producing property acquisitions in each of the years presented affect the comparability of year−to−year financial and operating data. See Items 1 and 2, Business and Properties, "Acquisitions." All weighted average shares and per share data have been adjusted for the five−for−four stock split effected in December 2007 and the four−for−three stock split effected in March 2005. This information should be read in conjunction with Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements at Item 15(a).

(in millions except production, per share and per unit data)	2009	2008	2007	2006	2005
Consolidated Income Statement Data					
Revenues:					
Gas and natural gas liquids	$ 6,322	$ 5,728	$ 4,214	$ 3,490	$ 2,787
Oil and condensate	2,605	1,796	1,204	1,002	670
Gas gathering, processing and marketing	125	168	100	86	56
Other	12	3	(5)	(2)	6
Total Revenues	$ 9,064	$ 7,695	$ 5,513	$ 4,576	$ 3,519
Net Income	$ 2,019*(a)*	$ 1,912*(b)*	$ 1,691*(c)*	$ 1,860*(d)*	$ 1,152*(e)*
Earnings per common share: *(f)*					
Basic	$ 3.48	$ 3.58	$ 3.57	$ 4.07	$ 2.57
Diluted	$ 3.46	$ 3.54	$ 3.52	$ 4.02	$ 2.52
Cash dividends declared per common share	$ 0.500	$ 0.480	$ 0.408	$ 0.252*(g)*	$ 0.180
Consolidated Statement of Cash Flows Data					
Cash provided (used) by:					
Operating activities	$ 5,954	$ 5,235	$ 3,639	$ 2,859	$ 2,094
Investing activities	$ (4,057)	$ (13,006)	$ (7,345)	$ (3,036)	$ (2,908)
Financing activities	$ (1,913)	$ 7,796	$ 3,701	$ 180	$ 806
Consolidated Balance Sheet Data					
Property and equipment, net	$ 31,934	$ 31,281	$ 17,200	$ 10,824	$ 8,508
Total assets	$ 36,255	$ 38,254	$ 18,922	$ 12,885	$ 9,857
Total debt	$ 10,487	$ 11,959	$ 6,320	$ 3,451	$ 3,109
Stockholders' equity	$ 17,326	$ 17,347	$ 7,941	$ 5,865	$ 4,209
Operating Data					
Average daily production:					
Gas (Mcf)	2,342,488	1,905,443	1,457,802	1,186,330	1,033,143
Natural gas liquids (Bbls)	20,560	15,624	13,545	11,854	10,445
Oil (Bbls)	66,297	56,025	47,047	45,041	39,051
Mcfe	2,863,631	2,335,336	1,821,353	1,527,705	1,330,121
Average realized sales price:					
Gas (per Mcf)	$ 7.13	$ 7.81	$ 7.50	$ 7.69	$ 7.04
Natural gas liquids (per Bbl)	$ 30.03	$ 48.76	$ 45.37	$ 37.03	$ 34.10
Oil (per Bbl)	$ 107.65	$ 87.59	$ 70.08	$ 60.96	$ 47.03
Production expense (per Mcfe)	$ 0.96	$ 1.10	$ 0.93	$ 0.88	$ 0.84
Taxes, transportation and other expense (per Mcfe)	$ 0.65	$ 0.82	$ 0.67	$ 0.67	$ 0.63
Proved reserves:					
Gas (Mcf)	12,501.7	11,802.9	9,441.1	6,944.2	6,085.6
Natural gas liquids (Bbls)	93.2	75.8	66.8	53.0	47.4
Oil (Bbls)	294.4	267.5	241.2	214.4	208.7
Mcfe	14,827.2	13,862.4	11,289.0	8,548.6	7,622.2
Other Data					
Ratio of earnings to fixed charges *(h)*	6.5	6.6	9.6	15.2	11.7

(a) Includes pre−tax effects of a $130 million non−cash derivative fair value loss and a $17 million gain on extinguishment of debt.
(b) Includes pre−tax effects of a $72 million non−cash derivative fair value gain and a $128 million impairment of proved properties.
(c) Includes pre−tax effects of a $43 million non−cash derivative fair value loss.
(d) Includes pre−tax effects of a gain on the distribution of Hugoton Royalty Trust units of $469 million, income tax expense related to enactment of a new State of Texas margin tax of $34 million and a $39 million non−cash derivative fair value gain.
(e) Includes pre−tax effects of a $39 million non−cash derivative fair value gain, non−cash performance award compensation of $34 million, and a gain of $10 million on the exchange of producing properties.
(f) Effective January 1, 2009, we adopted the authoritative guidance for earnings per share as it relates to determining whether instruments granted in share based payment transactions are participating securities. Under the guidance, share−based payment awards that contain nonforfeitable rights to dividends, as is the case with our restricted and performance shares, are participating securities and therefore should be included in computing earnings per share using the two−class method. As a result of adoption, we retrospectively adjusted the calculation of our 2008 and prior periods' earnings per share on a basis consistent with 2009.
(g) Excludes the May 2006 distribution of all of the Hugoton Royalty Trust units owned by the Company to its stockholders as a dividend with a market value of approximately $1.35 per common share.
(h) For purposes of calculating this ratio, earnings are before income tax and fixed charges. Fixed charges include interest costs and the portion of rentals considered to be representative of the interest factor.

Item 7. *MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS*

The following discussion and analysis should be read in conjunction with Item 6, Selected Financial Data, and the Consolidated Financial Statements at Item 15(a). Unless otherwise indicated, throughout this discussion the term "Mcfe" refers to thousands of cubic feet of gas equivalent quantities produced for the indicated period, with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

Overview

Our business is to produce and sell natural gas, natural gas liquids and crude oil from our predominantly southwestern and central U.S. properties, most of which we operate. Because our gathering, processing and marketing functions are ancillary to and dependent upon our production of natural gas, natural gas liquids and crude oil, we have determined that our business comprises only one industry segment.

On December 13, 2009, we entered into a definitive merger agreement with Exxon Mobil Corporation under which we would become a wholly owned subsidiary of ExxonMobil. As a result of the merger, each outstanding share of our common stock will be converted into 0.7098 shares of ExxonMobil common stock. Completion of the merger remains subject to certain conditions, including the adoption of the merger agreement by our stockholders, as well as certain governmental and regulatory approvals. We currently expect to complete the merger in the second quarter of 2010, however, no assurance can be given as to when, or if, the merger will occur.

In 2009, we achieved the following record financial and operating results:

- Average daily gas production was 2.34 Bcf, a 23% increase from 2008, average daily oil production was 66.3 MBbls, an 18% increase from 2008, and average daily natural gas liquids production was 20.6 MBbls, a 32% increase from 2008.
- Year−end proved reserves were 14.83 Tcfe, a 7% increase from year−end 2008.
- Cash flow from operating activities was $6.0 billion, a 14% increase from 2008.
- Long−term debt including current maturities was $10.5 billion, a $1.5 billion, or 12% decrease from year−end 2008.

We achieve production and proved reserve growth through a combination of low−risk development, generally funded by cash flow from operating activities, and acquisitions of both producing and unproved properties. Funding sources for our acquisitions include proceeds from sales of public and private equity and debt, bank or commercial paper borrowings and cash flow from operating activities. During 2009, we acquired $30 million of proved properties with proved reserves of 22.4 Bcf of natural gas and 0.1 million Bbls of natural gas liquids as well as $224 million of unproved properties. Our 2010 development budget is $3.37 billion. Additionally, $530 million has been budgeted for the construction of pipeline infrastructure and compression and processing facilities.

In a trend that began in 2004 and continued until mid−2008, commodity prices for natural gas, natural gas liquids and crude oil increased significantly. However, due to oversupply concerns, tightened credit markets and lower demand in slowing U.S. and global economies, commodity prices declined sharply in the second half of 2008. In 2009, signs of economic improvement resulted in higher oil prices but oversupply concerns continued to weigh on natural gas prices throughout the year (see “Significant Events, Transactions and Conditions−Product Prices”).

The higher prices in recent years led to increased activity in the industry, including the highest drilling rig levels in 25 years and increased demand for oil and gas properties. All of these factors led to significant cost inflation throughout the industry—such as labor, production expenses, drilling costs and acquisition prices. As a result of the U.S. and global recession and tightened credit markets, which led to sharp declines in commodity prices in the latter half of 2008, drilling rig counts decreased, acquisition activity slowed, and all industry costs declined.

Like all oil and gas exploration and production companies, we face the challenge of natural production decline. An oil and gas exploration and production company depletes part of its asset base with each unit of production. Despite this natural decline, we have been able to grow our production through acquisitions and drilling, adding more reserves than we produce. We also attempt to manage our natural decline by combining the acquisition of mature properties with shallower decline rates with the drilling of new wells that have higher decline rates. This has allowed us to keep our natural decline rate lower than the industry average. Future growth will depend on our ability to continue to add reserves in excess of production.

Our goal for 2010 is to increase production by approximately 10%. To achieve future production and reserve growth, we will continue to evaluate development projects and acquisitions that meet our criteria. We cannot ensure that we will be able to find properties that meet our acquisition criteria and that we can purchase such properties on acceptable terms (see “Liquidity and Capital Resources−Capital Expenditures”).

Increased activity in the oil and gas producing industry also had an effect on our ability to hire qualified people including not only operational employees, but also all classifications of industry−specific professionals. However, with the recent decrease in industry activity, it has become easier to find qualified employees. We continue to hire the employees we need to adequately staff our operations. Our employee turnover continues to remain low with total turnover of 5.6% in 2009 and 7.2% in 2008.

Sales prices for our natural gas, oil and natural gas liquids production are influenced by supply and demand conditions over which we have little or no control, including weather and regional and global economic conditions. To provide predictable production growth, we may hedge a portion of our production at commodity prices management deems attractive to ensure stable cash flow margins to fund our operating commitments and development program. As of February 2010, we have hedged 1.25 Bcf per day of our 2010 natural gas production at an average NYMEX price of $7.49 per Mcf and 70 MBbls per day of our 2010 crude oil production at an average NYMEX price of $95.70 per Bbl. Our average realized price on hedged production will be lower than these average NYMEX prices because of location, quality and other adjustments.

In 2010, given our hedge position and current commodity strip pricing, we expect to generate enough cash flow from operations to fund our capital expenditures and to have the ability to reduce debt by more than $500 million.

Table of Contents

The combined effect of higher oil prices, a 23% increase in gas production, an 18% increase in oil production and a 31% increase in natural gas liquids production partially offset by decreased natural gas and natural gas liquids prices resulted in an 18% increase in total revenues to $9.1 billion in 2009 from $7.7 billion in 2008. On a per Mcfe produced basis, total revenues were $8.67 in 2009, a 4% decrease from $9.00 in 2008.

We analyze on a per Mcfe produced basis, the following expenses, most of which trend with changes in production:

	2009	2008	Increase (Decrease)
Production	$0.96	$1.10	(13)%
Taxes, transportation and other	0.65	0.82	(21)%
Depreciation, depletion and amortization	2.95	2.37	24%
Accretion of discount in asset retirement obligation	0.04	0.04	—
General and administrative, excluding stock compensation	0.21	0.25	(16)%
Interest	0.50	0.56	(11)%
	$5.31	$5.14	3%

Production expense per Mcfe declined 13% primarily because of decreased power, fuel, compression, carbon dioxide injection and water disposal costs. Power, fuel and carbon dioxide injection costs vary with product prices. Taxes, transportation and other expense is primarily based on product revenues. The 21% decrease in transportation and other expense is primarily because of lower product prices, before hedging, partially offset by higher property taxes primarily due to development and the 2008 acquisitions. The 24% increase in depreciation, depletion and amortization per Mcfe resulted from higher acquisition, development and facility costs, the effect of downward revisions to proved oil and gas reserves due to lower commodity prices and a $91 million, or $0.09 per Mcfe, increase in the impairment of unproved properties. These increases were partially offset by a decrease in the impairment of proved properties of $128 million, or $0.15 per Mcfe. General and administrative expense per Mcfe decreased 16% due to increased production outpacing personnel and other expenses related to Company growth. The 11% decrease in interest expense is primarily because of increased production and a gain on extinguishment of debt of $17 million, which was partially offset by a 10% increase in weighted average borrowings to fund our 2008 acquisitions.

Significant expenses that generally do not trend with production include:

Non−cash stock incentive compensation. Stock incentive compensation expense was $137 million in 2009 compared to $170 million in 2008. The decrease is primarily related to a decline in both the number and value of grants made in 2009 compared to 2008.

Derivative fair value (gain) loss. This is the net realized and unrealized gain or loss on derivative financial instruments that does not qualify for hedge accounting treatment and fluctuates based on changes in the fair value of underlying commodities. The net derivative fair value loss was $24 million in 2009 compared to a gain of $85 million in 2008.

Our primary sources of liquidity are cash flow from operating activities, borrowings under either our revolving credit agreement, our commercial paper program, or our other unsecured and uncommitted lines of credit and public and private offerings of equity and debt. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest cost, interest rate volatility and financing risk (See “Liquidity and Capital Resources—Financing”).

Significant Events, Transactions and Conditions

The following events, transactions and conditions affect the comparability of results of operations and financial condition for each of the years ended December 31, 2009, 2008 and 2007 and may impact future operations and financial condition.

Table of Contents

Acquisitions. We acquired proved and unproved properties at a total cost of $254 million in 2009, $11.0 billion in 2008 and $4.0 billion in 2007, which were funded by a combination of proceeds from sales of common stock and senior notes, borrowings under either our bank credit facilities or commercial paper program and cash flow from operating activities. We made no significant acquisitions in 2009. The following are significant acquisitions in 2008 and 2007:

	Closing Date	Seller	Amount (in millions)	Acquisition Area
2008	January to June	Various	$ 2,253	Eastern and San Juan Regions, Barnett, Fayetteville, Woodford and Marcellus Shales
	May	Southwestern Energy Company	520	Fayetteville Shale
	July	Linn Energy, LLC	600	Marcellus Shale
		Headington Oil Company	1,804	Bakken Shale
	September	Hunt Petroleum Corporation	4,315*(a)*	Eastern Region, South Texas and Gulf Coast Region and North Sea
	October	Hollis R. Sullivan, Inc.	800	Barnett Shale
2007	July	Dominion Resources, Inc.	2,576	Rocky Mountain Region, San Juan Basin and South Texas
	October	Various	550	Barnett Shale

(a) Represents a portion of the allocated purchase price of Hunt Petroleum Corporation and includes an allocation of $4.1 billion to proved properties and $250 million to unproved properties. See Note 14 to the Consolidated Financial Statements.

2009, 2008 and 2007 Development and Exploration Programs. Gas development was concentrated in East Texas and the Barnett, Fayetteville and Woodford shales in 2009. In 2008 and 2007, gas development focused on East Texas and the Barnett Shale. Oil development was concentrated primarily in the Permian Basin and Bakken Shale in 2009 and primarily the Permian Basin during 2008 and 2007. Development costs totaled $2.5 billion in 2009, $3.4 billion in 2008 and $2.5 billion in 2007. Exploration activity in 2009 and 2008 was primarily drilling and geological and geophysical analysis, including seismic studies in the South Texas and Gulf Coast Region and the Woodford and Fayetteville Shales. Exploratory costs were $500 million in 2009, $517 million in 2008 and $257 million in 2007. Our development and exploration activities are generally funded by cash flow from operations.

2010 Acquisition, Development and Exploration Program. We have budgeted $3.37 billion for our 2010 development and exploration program, which we expect to fund using cash flow from operations. We plan to drill about 988 (833 net) development wells and perform approximately 865 (720 net) workovers and recompletions in 2010. Drilling plans are dependent upon product prices. While we expect to focus primarily on development activities in 2010, as a course of business, we review acquisition opportunities. If acquisition, development and exploration expenditures exceed cash flow from operations, we expect to obtain additional funding through our bank credit facilities, our commercial paper program, public or private issuance of debt or equity, or asset sales. Our total budget for acquisitions, development and exploration will be adjusted to focus on opportunities offering the highest rates of return. Additionally, $530 million has been budgeted for the construction of pipeline infrastructure and compression and processing facilities.

Product Prices. In addition to supply and demand, oil and gas prices are affected by seasonal, political and other conditions we generally cannot control or predict.

Gas. Natural gas prices are affected by the level of North American production, weather, the U.S. economy, storage levels, crude oil prices and import levels of liquefied natural gas. Natural gas competes with alternative energy sources as fuel for heating and the generation of electricity. In the first part of 2008, prices for natural gas increased significantly reaching as high as $13 per MMBtu in July 2008. However, higher than average gas in storage caused by shale gas development and lower demand due to the U.S. recession caused natural gas prices to drop below $3 per MMBtu in September 2009. The onset of winter and decreased production has resulted in higher recent gas prices. We expect gas prices to remain volatile. As described under “Hedging Activities” below, we use commodity price hedging instruments to reduce our exposure to gas price fluctuations. The following are comparative average gas prices for the last three years:

	Year Ended December 31		
(per Mcf)	2009	2008	2007
Average NYMEX price	$3.99	$9.03	$6.86
Average realized sales price	$7.13	$7.81	$7.50
Average realized sales price excluding hedging	$3.67	$8.04	$6.26

At February 19, 2010, the average NYMEX gas price for the following 12 months was $5.50 per MMBtu. As computed on an energy equivalent basis, our proved reserves were 84% natural gas at December 31, 2009. After considering hedges in place as of February 19, 2010, we estimate that a $0.10 per Mcf change in the average gas sales price would result in approximately a $44 million change in 2010 annual operating cash flow before income taxes.

Oil. Crude oil prices are generally determined by global supply and demand. In the first part of 2008, prices for oil increased significantly reaching a record high above $147 per Bbl in July 2008. However, lower demand as a result of the global economic situation caused oil prices to decline to below $40 last winter. Signs of possible economic improvement have resulted in higher oil prices. We expect oil prices to remain volatile. As described under “Hedging Activities” below, we use commodity price hedging instruments to reduce our exposure to oil price fluctuations. The following are comparative average oil prices for the last three years:

	Year Ended December 31		
(per Bbl)	2009	2008	2007
Average NYMEX price	$ 61.82	$99.75	$72.39
Average realized sales price	$107.65	$87.59	$70.08
Average realized sales price excluding hedging	$ 57.10	$93.17	$68.68

At February 19, 2010, the average NYMEX oil price for the following 12 months was $81.55 per Bbl. After considering hedges in place as of February 19, 2010, we estimate that a $1.00 per barrel change in the average oil sales price would result in a minimal change in 2010 annual operating cash flow before income taxes.

Hedging Activities. We may enter futures contracts, collars and basis swap agreements, as well as fixed−price physical delivery contracts, to hedge our exposure to product price volatility. Our policy is to consider hedging a portion of our production at commodity prices management deems attractive. While there is a risk we may not be able to realize the full benefit of rising prices, management plans to continue its hedging strategy because of the benefits of predictable, stable cash flows.

In 2009, all hedging activities increased gas revenue by $3.0 billion and oil revenue by $1.2 billion. In 2008, all hedging activities decreased gas revenue by $159 million, natural gas liquids revenue by $19 million and oil revenue by $114 million.

The following summarizes our NYMEX hedging positions under futures contracts and swap agreements as of February 2010, excluding basis adjustments.

Our average daily production was 2.37 Bcf of gas, 64.6 MBbls of oil and 21.2 MBbls of natural gas liquids in fourth quarter 2009. Prices to be realized for hedged production will be less than these NYMEX prices because of location, quality and other adjustments. See Note 8 to the Consolidated Financial Statements.

	Production Period	Mcf per Day	Weighted Average NYMEX Price Per Mcf
2010	January to December	1,250,000	$ 7.49
2011	January to December	250,000	$ 7.02

	Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl
2010	January to December	70,000	$ 95.70

Early Settlement of Hedges. In December 2008 and January 2009, we entered into early settlement and reset arrangements with eight financial counterparties covering a portion of our 2009 natural gas and crude oil hedge volumes. As a result of these early settlements, we received approximately $2.7 billion ($1.7 billion after−tax) which was used to reduce outstanding debt. Of this amount, $453 million ($287 million after−tax) was received in 2008 and the remainder was received in 2009. Under cash flow hedge accounting, the $453 million received in 2008 was included in accumulated other comprehensive income (loss) at December 31, 2008, and was recognized in earnings during 2009 as the hedged production occurred.

Derivative Fair Value (Gain) Loss. We record in our income statements realized and unrealized derivative fair value gains and losses related to derivatives that do not qualify for hedge accounting, as well as the ineffective portion of hedge derivatives. We recorded a net derivative fair value loss of $24 million in 2009 and net derivative fair value gains of $85 million in 2008 and $11 million in 2007. Of these amounts, a $25 million gain in 2009, a $1 million gain in 2008 and an $11 million gain in 2007 was due to the ineffective portion of hedge derivatives. These ineffective hedge derivative gains and losses are primarily because of fluctuating oil and gas prices and their effect on hedges of production in areas without corresponding basis or location differential swap contracts.

Derivative fair value (gain) loss in 2009 includes a $17 million loss ($11 million after−tax) on certain crude oil swap agreements that did not qualify for hedge accounting. Derivative fair value (gain) loss in 2008 includes a $38 million loss ($24 million after−tax) on certain natural gas futures that no longer qualify for hedge accounting due to the September 2008 bankruptcy filing of Lehman Brothers Holding Inc., the parent company of one of our counterparties. The 2008 derivative fair value (gain) loss also includes a $78 million gain ($50 million after−tax) on certain crude oil swap agreements that did not qualify for hedge accounting.

Unrealized derivative gains and losses associated with effective cash flow hedges are recorded in stockholders' equity as accumulated other comprehensive income (loss). At December 31, 2009, we have an unrealized pre−tax gain of $1.1 billion in accumulated other comprehensive income (loss) related to the fair value of derivatives designated as cash flow hedges of natural gas and crude oil price risk. Based on December 31 mark−to−market prices, essentially all of this fair value gain is expected to be reclassified into earnings in 2010. The actual reclassification to earnings will be based on mark−to−market prices at contract settlement date.

Stock−Based Compensation. Stock compensation totaled $137 million in 2009, $170 million in 2008 and $65 million in 2007. As of December 31, 2009, stock compensation expense is expected to total $90 million in 2010, $45 million in 2011, $18 million in 2012 and $8 million in 2013 related to all outstanding stock awards. These expected costs are subject to change for stock incentive awards granted after December 31, 2009.

*Senior Note Offering*s. In July 2007, we sold $300 million of 5.9% senior notes due August 1, 2012, $450 million of 6.25% senior notes due August 1, 2017 and $500 million of 6.75% senior notes due August 1, 2037. In August 2007, we sold an additional $250 million of the 5.9% senior notes, $300 million of the 6.25% senior notes and $450 million of the 6.75% senior notes that constituted a further issuance of the senior notes issued in July 2007. Net proceeds of $2.24 billion were used to fund a portion of the acquisition of properties from Dominion Resources, Inc. and to pay down outstanding commercial paper borrowings.

In April 2008, we sold $400 million of 4.625% senior notes due June 15, 2013, $800 million of 5.50% senior notes due June 15, 2018 and $800 million of 6.375% senior notes due June 15, 2038. In August 2008, we sold $250 million of 5.00% senior notes due August 1, 2010, $500 million of 5.75% senior notes due December 15, 2013, $1.0 billion of 6.50% senior notes due December 15, 2018 and $500 million of 6.75% senior notes due August 1, 2037. The notes due 2037 constitute a further issuance of the 6.75% senior notes issued in July 2007. Proceeds from the senior notes were used to fund property acquisitions and reduce bank debt.

Common Stock Transactions. In June 2007, we completed a public offering of 21.6 million common shares at $48.40 per share. After underwriting discount and other offering costs of $35 million, net proceeds of $1.0 billion were used to fund a portion of the acquisition of natural gas and oil properties from Dominion Resources, Inc.

In February 2008, we completed a public offering of 23 million common shares at $55.00 per share. After underwriting discount and other offering costs of $42 million, net proceeds of $1.2 billion were used to fund a portion of the $2.3 billion of property acquisitions closed in the first six months of 2008 and to repay indebtedness under our commercial paper program.

In August 2008, we completed a public offering of 29.9 million common shares at $48.00 per share. After underwriting discount and other offering costs of $48 million, net proceeds of $1.4 billion were used to fund property acquisitions and to pay down outstanding commercial paper borrowings.

Shelf Registration Statement. In June 2009, we filed a shelf registration statement with the Securities and Exchange Commission to potentially offer securities which could include debt securities or common stock. The securities will be offered at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities are to be used for general corporate purposes, including the reduction of bank debt.

In July 2008, we registered 11.7 million shares of our common stock, which were issued to the sellers in the acquisition of properties from Headington Oil Company. In September 2008, we registered 23.5 million shares of our common stock, which were issued to the sellers in the acquisition of Hunt Petroleum Corporation.

Repurchase of Senior Notes. In 2009, we repurchased $200 million total face amount of senior notes, including $2 million of our 5.00% senior notes due 2015, $15 million of our 6.25% senior notes due 2017, $27 million of our 5.50% senior notes due 2018, $9 million of our 6.10% senior notes due 2036, $51 million of our 6.75% senior notes due 2037 and $96 million of our 6.375% senior notes due 2038. In connection with these repurchases, we recognized a $17 million gain on extinguishment of debt, net of unamortized discounts and the write−off of deferred debt offering costs. These gains were netted against interest expense in the consolidated income statements.

Results of Operations

2009 Compared to 2008

For the year 2009, net income was $2.0 billion compared with net income of $1.9 billion for 2008. Earnings for 2009 include a $130 million ($83 million after−tax) non−cash derivative fair value loss and a $17 million ($11 million after−tax) gain on extinguishment of debt. Earnings for 2008 include a $72 million ($46 million after−tax) non−cash derivative fair value gain and a $128 million ($81 million after−tax) impairment of proved properties.

Revenues for 2009 were $9.1 billion, or 18% higher than 2008 revenues of $7.7 billion. Gas and natural gas liquids revenue increased $594 million because of a 23% increase in gas production and a 31% increase in natural gas liquids production partially offset by a 9% decrease in gas prices from an average of $7.81 per Mcf in 2008 to $7.13 in 2009 and a 38% decrease in natural gas liquids prices from an average price of $48.76 per Bbl in 2008 to $30.03 in 2009 (see “Significant Events, Transactions and Conditions – Product Prices – Gas” above). Increased production was attributable to our 2009 development program and the 2008 acquisitions.

Oil revenue increased $809 million because of an 18% increase in production, primarily due to our 2009 development program and the 2008 acquisitions, and a 23% increase in oil prices from an average of $87.59 per Bbl in 2008 to $107.65 in 2009 (see “Significant Events, Transactions and Conditions – Product Prices – Oil” above).

Expenses for 2009 totaled $5.4 billion, or 28% higher than total 2008 expenses of $4.2 billion. Increased expenses are generally related to increased production from development and acquisitions and related Company growth. Production expense increased $57 million primarily because of increased overall production and increased maintenance costs, partially offset by decreased power, fuel and carbon dioxide injection costs. Production expense per Mcfe decreased from $1.10 in 2008 to $0.96 in 2009 primarily because of decreased power, fuel, compression, carbon dioxide injection and water disposal costs. Power, fuel and carbon dioxide injection costs vary with product prices. Taxes, transportation and other expense decreased $25 million and per Mcfe decreased from $0.82 in 2008 to $0.65 in 2009 primarily because of lower production taxes and transportation costs related to lower product prices, before hedging, partially offset by higher property taxes related to development and the 2008 acquisitions. Exploration expense decreased $11 million primarily because of decreased seismic costs, partially offset by increased dry hole expense.

Depreciation, depletion and amortization (DD&A) increased $1.1 billion primarily because of higher acquisition, development and facility costs and increased production. On a per Mcfe basis, DD&A increased from $2.37 in 2008 to $2.95 in 2009 because of higher acquisition, development and facility costs per Mcfe, the effect of net downward revisions to proved oil and gas reserves due to lower commodity prices and a $91 million, or $0.09 per Mcfe, increase in the impairment of unproved properties. This was partially offset by a $128 million decrease in the impairment of proved properties. Excluding the proved property impairment, 2008 DD&A would have been $2.22 per Mcfe.

General and administrative expense decreased $26 million. Of this decrease, $33 million was the result of a decrease in non−cash incentive award compensation primarily due to a decline in both the number and value of incentive award grants made in 2009 compared to 2008. Increased general and administrative expense, excluding non−cash incentive award compensation, is primarily because of higher employee expenses related to Company growth. Excluding non−cash incentive award compensation, general and administrative expense per Mcfe was $0.21 in 2009 compared to $0.25 in 2008 as increased production outpaced increased personnel and other expenses related to Company growth.

The derivative fair value loss for 2009 was $24 million compared to a gain of $85 million in 2008. The 2009 loss and 2008 gain were primarily related to certain crude oil swap agreements that did not qualify for hedge accounting. See Note 7 to Consolidated Financial Statements.

Interest expense increased $42 million, primarily because of a 10% increase in the weighted average borrowings to partially fund 2008 property acquisitions partially offset by a $17 million gain on the extinguishment of debt. Interest expense per Mcfe decreased from $0.56 in 2008 to $0.50 in 2009 due to increased production and the gain on extinguishment of debt.

The 2009 effective income tax rate was 36.2%, as compared to a 36.8% effective rate for 2008. The current portion of total income taxes was 29% in 2009 and 13% in 2008. The higher current portion of total income taxes was primarily due to decreased development costs. Development costs are generally deducted for income tax purposes over a shorter term than for financial accounting purposes.

2008 Compared to 2007

For the year 2008, net income was $1.9 billion compared with net income of $1.7 billion for 2007. Earnings for 2008 include a $72 million ($46 million after−tax) non−cash derivative fair value gain and a $128 million ($81 million after−tax) impairment of proved properties. Earnings for 2007 include a $43 million ($28 million after−tax) non−cash derivative fair value loss.

Revenues for 2008 were $7.7 billion, or 40% higher than 2007 revenues of $5.5 billion. Gas and natural gas liquids revenue increased $1.5 billion because of a 31% increase in gas production, a 16% increase in natural gas liquids production, a 4% increase in gas prices from an average of $7.50 per Mcf in 2007 to $7.81 in 2008 and a

7% increase in natural gas liquids prices from an average price of $45.37 per Bbl in 2007 to $48.76 in 2008 (see “Significant Events, Transactions and Conditions – Product Prices – Gas” above). Increased production was attributable to the 2008 acquisition and development program.

Oil revenue increased $592 million because of a 19% increase in production, primarily due to the 2008 acquisition and development program, and a 25% increase in oil prices from an average of $70.08 per Bbl in 2007 to $87.59 in 2008 (see “Significant Events, Transactions and Conditions – Product Prices – Oil” above).

Expenses for 2008 totaled $4.2 billion, or 60% higher than total 2007 expenses of $2.6 billion. Increased expenses are generally related to increased production from acquisitions and development and related Company growth. Production expense increased $327 million and per Mcfe increased from $0.93 in 2007 to $1.10 in 2008 primarily because of overall price increases as well as increased water disposal, power and fuel costs and certain one−time and discretionary items related to recent property acquisitions including increased compression, maintenance and workover costs. Taxes, transportation and other expense increased $259 million and per Mcfe increased from $0.67 in 2007 to $0.82 in 2008 primarily because of higher product prices and higher transportation costs related to higher throughput volumes. Exploration expense increased $36 million primarily because of increased seismic costs in the Gulf of Mexico and the Woodford and Fayetteville shales.

Depreciation, depletion and amortization (DD&A) increased $838 million primarily because of increased production. On an Mcfe basis, DD&A increased 33% from $1.78 in 2007 to $2.37 in 2008 because of higher acquisition, development and facility costs as well as an impairment of proved properties of approximately $128 million, or $0.15 per Mcfe, and a $107 million, or $0.13 per Mcfe, increase in the impairment of unproved properties.

General and administrative expense increased $151 million. Of this increase, $105 million was the result of an increase in non−cash incentive award compensation primarily as a result of additional incentive award grants in 2007 and 2008. Increased general and administrative expense, excluding non−cash incentive award compensation, is primarily because of higher employee expenses related to Company growth. Excluding non−cash incentive award compensation, general and administrative expense per Mcfe was $0.25 in 2008 and 2007 as increased personnel and other costs were offset by increased production.

The derivative fair value gain for 2008 was $85 million compared to $11 million in 2007. The 2008 gain is primarily related to the gain on certain crude oil swap agreements that did not qualify for hedge accounting. The 2007 gain is primarily related to the ineffective portion of hedge derivatives. See Note 7 to Consolidated Financial Statements.

Interest expense increased $232 million, primarily because of a 97% increase in the weighted average borrowings to partially fund property acquisitions. Interest expense per Mcfe increased from $0.38 in 2007 to $0.56 in 2008.

The 2008 effective income tax rate was 36.8%, as compared to a 36.0% effective rate for 2007. The current portion of total income taxes was 13% in 2008 and 31% in 2007. The decline in the current portion of total income taxes was primarily due to increased development costs and accelerated tax depreciation as allowed by changes to the tax rules in 2008. Development costs are generally deducted for income tax purposes over a shorter term than for financial accounting purposes.

Liquidity and Capital Resources

Our primary sources of liquidity are cash provided by operating activities, borrowings under either our revolving credit agreement, our other unsecured and uncommitted lines of credit or our commercial paper program, occasional proved property sales and private or public offerings of equity and debt. Other than for operations, our cash requirements are generally for the acquisition, exploration and development of oil and gas properties, and debt and dividend payments. Exploration and development expenditures and dividend payments have generally been funded by cash flow from operations. We believe that our sources of liquidity are adequate to fund our cash requirements in 2010.

Cash provided by operating activities was $6.0 billion in 2009, compared with cash provided by operating activities of $5.2 billion in 2008 and $3.6 billion in 2007. Increased cash provided by operating activities from 2008 to 2009 and from 2007 to 2008 was primarily because of increased production from acquisitions and development activity, and higher price realizations in 2008 compared to 2007. Also, 2008 benefited from the early settlement and reset arrangements with one of our financial counterparties (see "Significant Events, Transactions and Conditions – Early Settlement of Hedges" above). Cash provided by operating activities was decreased by changes in operating assets and liabilities of $265 million in 2009 and $72 million in 2007 and was increased by changes in operating assets and liabilities of $171 million in 2008. Changes in operating assets and liabilities are primarily the result of timing of cash receipts and disbursements. Cash provided by operating activities was also reduced by exploration expense, excluding dry hole expense, of $33 million in 2009, $66 million in 2008 and $31 million in 2007. Cash provided by operating activities is largely dependent on our production volumes as well as the prices received for oil and gas production. As of February 2010, we have hedged 1.25 Bcf per day of our 2010 natural gas production and 70 MBbls per day of our 2010 crude oil production. See "Significant Events, Transactions and Conditions—Product Prices" above.

During 2009, cash provided by operating activities of $6.0 billion was used to fund development costs, net property acquisitions and other net capital additions of $4.1 billion, dividends of $287 million and to pay down $1.5 billion of debt. The resulting decrease in cash and cash equivalents for the period was $16 million. During 2008, cash provided by operating activities of $5.2 billion, proceeds from the February and July 2008 common stock offerings of $2.6 billion, proceeds from the April and August 2008 debt offerings of $4.2 billion and proceeds from other borrowings of $1.1 billion were used to fund net property acquisitions, development costs and other net capital additions of $13.0 billion and dividends of $250 million. The resulting increase in cash and cash equivalents for the period was $25 million. During 2007, cash provided by operating activities of $3.6 billion, proceeds from the June 2007 common stock offering of $1.0 billion, proceeds from the July and August 2007 debt offerings of $2.2 billion and proceeds from other borrowings of $620 million were used to fund net property acquisitions, development costs and other net capital additions of $7.3 billion and dividends of $170 million. The decrease in cash and cash equivalents for the period was $5 million.

Financial Condition

Total assets decreased 5% from $38.3 billion at December 31, 2008 to $36.3 billion at December 31, 2009, primarily because of a $2.5 billion decrease in the fair value of outstanding derivatives contracts, partially offset by Company growth related to development. As of December 31, 2009, total capitalization was $27.8 billion, of which 38% was debt. Capitalization at December 31, 2008 was $29.3 billion, of which 41% was debt. The improvement in the debt−to−capitalization ratio from year−end 2008 to 2009 is primarily because of decreased debt.

Working Capital

We generally maintain low cash and cash equivalent balances because we use available funds to reduce either bank debt or borrowings under our commercial paper program. Short−term liquidity needs are satisfied by either bank commitments under our loan agreements or our commercial paper program (see "Financing" below). Because of this, and since our principal source of operating cash flows (i.e., proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. Working capital declined from a positive position of $1.3 billion at December 31, 2008 to a positive position of $247 million at December 31, 2009. Excluding the effects of derivative fair value and deferred tax current assets and liabilities, working capital decreased $34 million from a negative position of $432 million at December 31, 2008 to a negative position of $466 million at December 31, 2009. This decrease is a result of decreased accounts receivable due to lower product prices, excluding hedges, and the increase in current maturities of long−term debt, partially offset by decreased accounts payable and accrued liabilities primarily related to lower commodity prices, excluding hedges, and lower drilling activity. Any cash settlement of hedge derivatives should generally be offset by increased or decreased cash flows from our sales of related production. Therefore, we believe that most of the changes in derivative fair value assets and liabilities are offset by changes in value of our oil and gas reserves. This offsetting change in value of oil and gas reserves, however, is not recorded in the financial statements.

When the monthly cash settlement amount under our hedge derivatives is calculated, if market prices are higher than the fixed contract prices, we are required to pay the contract counterparties. While this payment will ultimately be funded by higher prices received from sale of our production, production receipts lag payments to the counterparties by as much as 55 days. Any interim cash needs are funded by borrowings under either our revolving credit agreement, our other unsecured and uncommitted lines of credit, or our commercial paper program. None of our derivative contracts have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date.

We believe that our expected cash flow from operations, as well as our various funding facilities provide us with adequate liquidity to meet our current obligations. In 2010, given our hedge position and current commodity strip pricing, we expect to generate enough cash flow from operations to fund our capital expenditures and to have the ability to reduce debt by more than $500 million. The expected debt reduction may include bank facilities, commercial paper or senior notes.

Most of our receivables are from a diverse group of companies including major energy companies, pipeline companies, local distribution companies, financial institutions and end−users in various industries. We currently have greater concentrations of credit with several A− or better rated companies. Letters of credit or other appropriate forms of security are obtained as considered necessary to limit risk of loss. Financial and commodity−based futures and swap contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. This exposure is diversified among major investment grade financial institutions, and we have master netting agreements with most counterparties that provide for offsetting payables against receivables from separate derivative contracts. In September 2008, the parent company of one of our counterparties, Lehman Brothers Holdings Inc, filed for bankruptcy, and we recognized a $38 million ($24 million after−tax) loss in derivative fair value (gain) loss in the income statement.

Financing

On December 31, 2009, we had no borrowings under our revolving credit agreement with commercial banks, and we had available borrowing capacity of $2.2 billion net of our commercial paper borrowings. We use the facility for general corporate purposes and as a backup facility for our commercial paper program. We have the option, with bank approval, to increase the commitment up to an additional $660 million. The interest rate on any borrowing is generally based on LIBOR plus 0.40%. When utilization of available commitments is greater than 50%, then the interest rate on our borrowings is increased by 0.05%. Interest is paid at maturity, or quarterly if the term is for a period of 90 days or more. We also incur a commitment fee on unused borrowing commitments, which is 0.09%. The agreement requires us to maintain a debt−to−total capitalization ratio of not more than 65%.

Our commercial paper program availability is $2.84 billion. Borrowings under the commercial paper program reduce our available capacity under the revolving credit facility on a dollar−for−dollar basis. The commercial paper borrowings may have terms up to 397 days and bear interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. On December 31, 2009, borrowings under our commercial paper program were $622 million at a weighted average interest rate of 0.3%.

We have unsecured and uncommitted lines of credit with commercial banks totaling $100 million. As of December 31, 2009, there were no borrowings under these lines.

In 2009, we repurchased $200 million total face amount of senior notes, including $2 million of our 5.00% senior notes due 2015, $15 million of our 6.25% senior notes due 2017, $27 million of our 5.50% senior notes due 2018, $9 million of our 6.10% senior notes due 2036, $51 million of our 6.75% senior notes due 2037 and $96 million of our 6.375% senior notes due 2038. In connection with these repurchases, we recognized a $17 million gain on extinguishment of debt, net of unamortized discounts and the write−off of deferred debt offering costs. These gains were netted against interest expense in the consolidated income statements.

During 2009, we utilized cash flow from operations to reduce our long−term debt including current maturities by $1.5 billion, reducing total debt to $10.5 billion at December 31, 2009.

Our revolving credit and term loan agreements contain no clauses that permit the lenders to accelerate payments or refuse to lend based on any unspecified material adverse change. However, the agreements allow the lenders to accelerate payments and terminate lending commitments if we default on any principal or interest payments under the loan agreements or our swap agreements or under any other payment obligation in excess of $100 million. We were in compliance with the terms of the credit and term loan agreements as of December 31, 2009.

Our ability to access funds under our credit agreements is not directly subject to a “material adverse effect” clause, rather we have to make certain representations, some of which contain a specific “material adverse effect” provision which limits our scope to the representation made, though none are related to our current financial situation. We are in compliance with the representations and do not believe that making the representations is a material restriction on our ability to access funds under our credit agreements.

Our senior unsecured long−term debt is currently rated Baa2 by Moody’s and BBB by Standard & Poor’s. Our short−term debt rating for our commercial paper program is currently rated P−2 by Moody’s and A−2 by Standard & Poor’s. The outlook from both rating agencies is under review pending the outcome of the proposed merger with ExxonMobil. ExxonMobil is currently rated Aaa by Moody’s and AAA by Standard & Poor’s.

A decline in our credit ratings with Moody’s and Standard & Poor’s does not trigger any drawdown restrictions or acceleration of maturity under our credit agreements. However, our cost of borrowing under our credit agreements is determined by our credit ratings. Therefore, even though a ratings downgrade would not accelerate scheduled maturities, it would adversely impact the interest rate on any borrowings under our revolving credit facility and term loans. Additionally, any downgrade to those ratings could increase our future borrowing costs and limit our access to debt capital markets.

Capital Expenditures

In 2009, exploration and development cash expenditures totaled $3.2 billion compared with $3.7 billion in 2008. We have budgeted $3.37 billion for the 2010 development and exploration program and an additional $530 million for the construction of pipeline infrastructure and compression and processing facilities. As we have done historically, we expect to fund the 2010 development program with cash flow from operations. Actual costs may vary significantly due to many factors, including development results and changes in drilling and service costs. We also may reevaluate our budget and drilling programs as a result of significant changes in oil and gas prices.

While we expect to focus on development activities in 2010, as a course of business, we actively review acquisition opportunities. If acquisition, development and exploration expenditures exceed cash flow from operations, we expect to obtain additional funding through our bank credit facilities, our commercial paper program, issuance of public or private debt or equity, or asset sales. Other than the requirement for us to maintain a debt−to−total capitalization ratio of not more than 65%, there are no restrictions under our revolving credit agreement that would affect our ability to use our remaining borrowing capacity.

To date, we have not incurred significant expenditures to comply with environmental or safety regulations, and we do not expect to during 2010. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Greenhouse Gas Emissions and Climate Change Regulation

There is an increased focus by local, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change. Various regulatory bodies have announced their intent to regulate GHG emissions. As these regulations are under development, we are unable to predict the total impact of the potential regulations upon our business, and it is possible that we could face increases in operating costs in order to comply with GHG emissions legislation. We are reviewing, through our Climate Change Committee, issues involving GHG emissions, including assisting management in monitoring the science of climate change and making recommendations to help develop emission reduction programs.

Dividends

The Board of Directors declared quarterly dividends of $0.096 per common share for the first three quarters of 2007, $0.12 per common share for fourth quarter 2007 and each quarter in 2008 and $0.125 per common share for each quarter in 2009. On February 16, 2010, the Board of Directors declared a first quarter 2010 dividend of $0.125 per common share. In addition, under the terms of the merger agreement with ExxonMobil, during the period before the closing of the merger, we are prohibited from declaring, setting aside or paying any dividend or other distribution except for our regular quarterly cash dividend, which is not to exceed $0.125 per share. The merger agreement also provides that we will coordinate the declaration of dividends with ExxonMobil before the completion of the merger so that both our shareholders and the shareholders of ExxonMobil only receive, in any quarter, one dividend from each company.

Our ability to pay dividends is dependent upon our financial condition, earnings and cash flow from operations, the level of our capital expenditures, our future business prospects and other matters our Board deems relevant.

Off−Balance Sheet Arrangements

We do not have any investments in unconsolidated entities or persons that could materially affect the liquidity or the availability of capital resources. Under the terms of some of our operating leases for compressors, airplanes and vehicles, we have various residual value guarantees and other payment provisions upon our election to return the equipment under certain specified conditions. Guarantees related to these leases are not material. The only material off−balance sheet arrangements that we have entered into are those disclosed in the following table of contractual obligations and commitments.

Contractual Obligations and Commitments

The following summarizes our significant obligations and commitments to make future contractual payments as of December 31, 2009. We have not guaranteed the debt or obligations of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt or losses.

		Payments Due by Year					
(in millions)	**Total**	**2010**	**2011**	**2012**	**2013**	**2014**	**After 2014**
Debt	$ 10,522	$ 250	$ —	$ 900	$ 2,522	$ 500	$ 6,350
Operating leases	77	29	23	14	8	3	—
Drilling contracts	129	104	23	2	—	—	—
Purchase commitments	30	30	—	—	—	—	—
Transportation contracts	1,854	210	224	226	221	217	756
Derivative contract liabilities at December 31, 2009 fair value	173	167	3	3	—	—	—
Total	$ 12,785	$ 790	$ 273	$ 1,145	$ 2,751	$ 720	$ 7,106

Debt. Debt amounts represent scheduled maturities of our debt obligations at December 31, 2009, excluding $35 million of net discounts on our senior notes included in the carrying value of debt. At December 31, 2009, borrowings were $622 million under our commercial paper program. Because we had the intent and ability to refinance the balance due with borrowings under our credit facility due in April 2013, the $622 million outstanding under the commercial paper program is reflected in the table above as due in 2013. Borrowings of $600 million under our term loans are due in 2013, and our senior notes, totaling $9.3 billion, are due 2010 through 2038. For further information regarding long−term debt, see Note 3 to Consolidated Financial Statements.

Drilling Contracts. We have contracts with various drilling contractors to use 50 drilling rigs with terms of up to three years. Early termination of these contracts at December 31, 2009 would have required us to pay maximum penalties of $66 million. Based upon our planned drilling activities, we do not expect to pay significant early termination penalties.

Transportation Contracts. We have entered firm transportation contracts with various pipelines for various terms through 2022. Under these contracts we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. Our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. We have generally delivered at least minimum volumes under these firm transportation contracts, therefore avoiding payment for deficiencies.

In November 2008, we completed an agreement to enter into a twelve−year firm transportation contract, contingent upon obtaining regulatory approvals and completion of a new pipeline that connects the Fayetteville Shale to ANR Pipeline and Trunkline Pipeline in Quitman County, Mississippi. Upon the pipeline's completion, currently expected in fourth quarter 2010, we will transport gas volumes for a transportation fee of up to $1.25 million per month plus fuel, currently expected to be 0.86% of the sales price. The potential effect of this agreement is not included in the above summary of our transportation contract commitments since our commitment is contingent upon completion of the pipeline.

Derivative Contracts. We have entered into futures contracts and swaps to hedge our exposure to natural gas and oil price fluctuations. If market prices are higher than the contract prices when the cash settlement amount is calculated, we are required to pay the contract counterparties. As of December 31, 2009, the current liability related to such contracts was $167 million and the noncurrent liability was $6 million. While such payments generally will be funded by higher prices received from the sale of our production, production receipts may be received as much as 55 days after payment to counterparties and can result in draws on our revolving credit facility, our other unsecured and uncommitted lines of credit or our commercial paper program. See Note 7 to Consolidated Financial Statements.

Related Party Transactions

Jack Randall, one of our nonemployee directors, was a co−founder and director of Randall & Dewey Partners, L.P., which was acquired by Jefferies Group, Inc. in 2005 and now operates as Jefferies & Company, Inc. Jefferies served as one of our financial advisors in connection with the announced merger with ExxonMobil. If the merger is completed, we have agreed to pay Jefferies a transaction fee of $24 million. In addition, we agreed to reimburse Jefferies for all reasonable and documented out−of−pocket expenses, including legal fees, incurred in connection with the services it provides to us in connection with the merger and have agreed to indemnify Jefferies against certain liabilities. In addition, Jefferies performed property acquisition advisory services for us in prior years. A division of Jefferies also performed co−manager services on our February and August 2008 and June 2007 common stock offerings and our April and July 2008 and July and August 2007 senior note offerings. We paid, for the credit of Jefferies, total fees of $11.8 million in 2008 and $3.4 million in 2007. There were no amounts payable at December 31, 2009 or 2008.

In February 2007, in recognition of the Chairman of the Board and Founder and as part of a charitable giving program to support higher education, the Board of Directors approved a conditional contribution of $6.8

million to assist in building an athletics and academic center at Baylor University. This contribution was paid in two equal installments of $3.4 million in each of 2007 and 2008. Concurrently, our Chairman of the Board and Founder, made a $3.2 million pledge for the same project. He fulfilled his obligation in 2008. In return for these contributions, we, along with our Chairman of the Board and Founder, obtained naming rights for the building and certain facilities within the building.

In November 2007, the Board of Directors approved and we paid our Chairman of the Board and Founder $150,000 for an easement across his property in North Texas plus an additional $36,000 for damages. The easement was for approximately 10,000 feet at the standard easement rate in the area of $15 per foot.

Critical Accounting Policies and Estimates

Our financial position and results of operations are significantly affected by accounting policies and estimates related to our oil and gas properties, proved reserves, asset retirement obligation and commodity prices and risk management, as summarized below.

Oil and Gas Property Accounting

Oil and gas exploration and production companies may elect to account for their property costs using either the “successful efforts” or “full cost” accounting method. Under the successful efforts method, unsuccessful exploratory well costs, as well as all exploratory geological and geophysical costs, are expensed. Under the full cost method, all exploration costs are capitalized, regardless of success. Selection of the oil and gas accounting method can have a significant impact on a company’s financial results. We use the successful efforts method of accounting and generally pursue acquisitions and development of proved reserves as opposed to exploration activities.

We evaluate possible impairment of producing properties when conditions indicate that the properties may be impaired. Such conditions include a significant decline in product prices which we believe to be other than temporary or a significant downward revision in estimated proved reserves for a field or area. An impairment provision must be recorded to adjust the net book value of the property to its estimated fair value if the net book value exceeds management’s estimate of future net cash flows from the property. The estimated fair value of the property is generally calculated as the discounted present value of future net cash flows. Our estimates of cash flows are based on the latest available proved reserve and production information and management’s estimates of future product prices and costs, based on available information such as forward strip prices and industry forecasts and analysis.

The impairment assessment process is primarily dependent upon the estimate of proved reserves. Any overstatement of estimated proved reserve quantities would result in an overstatement of estimated future net cash flows, which could result in an understated assessment of impairment. The subjectivity and risks associated with estimating proved reserves are discussed under “Oil and Gas Reserves” below. Prediction of product prices is subjective since prices are largely dependent upon supply and demand resulting from global and national conditions generally beyond our control. However, management’s assessment of product prices for purposes of impairment is consistent with that used in its business plans and investment decisions. While there is judgment involved in management’s estimate of future product prices, the potential impact on impairment has not been significant since product prices have been substantially higher than our net acquisition and development costs per Mcfe. However, with the deepening U.S. recession and the slowing global economy, product prices declined significantly, resulting in a change in our development drilling plans. Though projected product prices less expenses are still expected by management to be higher than our net acquisition and development costs per Mcfe for most of our properties, we recognized a $128 million impairment of proved properties in 2008. Prior to 2008, our historical impairment of proved properties had been limited to an immaterial impairment in 1998. We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impracticable to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome.

Oil and Gas Reserves

Our proved oil and gas reserves are estimated by independent petroleum engineers. Reserve engineering is a subjective process that is dependent upon the quality of available data and the interpretation thereof, including evaluations and extrapolations of well flow rates and reservoir pressure. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices, may justify revision of such estimates. Because proved reserves are required to be estimated using the 12−month average prices, estimated reserve quantities can be significantly impacted by changes in product prices.

Depreciation, depletion and amortization of producing properties is computed on the unit−of−production method based on estimated proved oil and gas reserves. While total DD&A expense for the life of a property is limited to the property’s total cost, proved reserve revisions result in a change in timing of when DD&A expense is recognized. Downward revisions of proved reserves result in an acceleration of DD&A expense, while upward revisions tend to lower the rate of DD&A expense recognition. As shown in Note 16 to the Consolidated Financial Statements, net downward revisions of proved reserves on an Mcfe basis occurred in 2009 and 2008, which will result in an increase in DD&A expense of approximately 3% in 2010 and resulted in an increase in DD&A expense of approximately 8% in 2009. Net upward revisions occurred to proved reserves on an Mcfe basis in 2007, resulting in a decrease in DD&A expense of approximately 1% in 2008. Based on proved reserves at December 31, 2009, we estimate that a 1% change in proved reserves would increase or decrease 2010 DD&A expense by approximately $34 million.

During 2009, development and exploration activities resulted in extensions, additions, discoveries and net revisions of proved reserves that were 190% of our 2009 production. Over the last five years, our proved reserve extensions, additions, discoveries and net revisions averaged 230% of our production for this period. Our proved reserve extensions, additions and discoveries in 2009 included an increase of 1.8 Tcfe in proved undeveloped reserves, or approximately 73% of our total extensions, additions and discoveries. The remaining extensions, additions and discoveries were proved developed reserves. Over the past five years, approximately 73% of our proved reserves extensions, additions and discoveries were proved undeveloped reserves. Our 2009 development drilling program resulted in the conversion of approximately 16% of our proved undeveloped reserves into proved developed reserves during the year. Development of our proved undeveloped reserves is not subject to significant uncertainties such as regulatory approvals, and we believe that we have adequate resources to develop these reserves, dependent on commodity prices not declining significantly. We believe that reserve additions, comparable to these historical reserve additions, are attainable in the near term future, subject to product prices and development costs remaining at levels to ensure economic viability.

The standardized measure of discounted future net cash flows and changes in such cash flows, as reported in Note 16 to Consolidated Financial Statements, are prepared using assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission. Such assumptions include 12−month average oil and gas prices, based on the first−day−of−the−month price for each month in the period, and year end costs for estimated future development and production expenditures. Prior to 2009, standardized measure was calculated using year end oil and gas prices and costs. Discounted future net cash flows are calculated using a 10% rate. Changes in any of these assumptions could have a significant impact on the standardized measure. Accordingly, the standardized measure does not represent management’s estimated current market value of proved reserves.

Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable federal, state and international laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset’s inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk−adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. For example, as we analyze actual plugging and abandonment information, we may revise our estimates of current costs, the assumed annual inflation of these costs and/or the assumed productive lives of our wells. During 2009, we revised our existing estimated asset retirement obligation by $7 million, or approximately 1% of the asset retirement obligation at December 31, 2008, based on a review of current plugging and abandonment costs. Over the past five years, revisions to the estimated asset retirement obligation averaged approximately 10% of the asset retirement obligation at the beginning of the year. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates.

Commodity Prices and Risk Management

Commodity prices significantly affect our operating results, financial condition, cash flows and ability to borrow funds. Current market oil and gas prices are affected by supply and demand as well as seasonal, political and other conditions which we generally cannot control. Oil and gas prices and markets are expected to continue their historical volatility. See "Significant Events, Transactions and Conditions—Product Prices" above.

We attempt to reduce our price risk on a portion of our production by entering into financial instruments such as futures contracts, collars and basis swap agreements, as well as fixed−price physical delivery contracts. While these instruments secure a certain price and, therefore, a certain cash flow, there is the risk that we may not be able to realize the full benefit of rising prices. These contracts also expose us to credit risk of nonperformance by the contract counterparties, all of which are major investment grade financial institutions. We attempt to limit our credit risk by obtaining letters of credit or other appropriate forms of security.

While our price risk management activities decrease the volatility of cash flows, they may obscure our reported financial condition. As required under U.S. generally accepted accounting principles, we record derivative financial instruments at their fair value, representing projected gains and losses to be realized upon settlement of these contracts in subsequent periods when related production occurs. These gains and losses are generally offset by increases and decreases in the market value of our proved reserves, which are not reflected in the financial statements. Derivatives that provide effective cash flow hedges are designated as hedges, and, to the extent the hedge is determined to be effective, we defer related unrealized fair value gains and losses in accumulated other comprehensive income (loss) until the hedged transaction occurs. See "Derivatives" under Note 1 to Consolidated Financial Statements regarding our accounting policy related to derivatives.

See also "Commodity Price Risk" under Item 7A, Quantitative and Qualitative Disclosures about Market Risk, for the effect of price changes on derivative fair value gains and losses.

Goodwill

Goodwill is not amortized to earnings but is tested, at least annually, for impairment at the reporting unit level. We conduct the goodwill impairment test effective October 1 of each year. Other events and changes in circumstances may also require goodwill to be tested for impairment between annual measurement dates. The first step of that process is to compare the fair value of the reporting unit to which goodwill has been assigned to the carrying amount of the associated net assets. If the estimated fair value is greater than the carrying amount of the reporting unit, then no impairment loss is required. The annual test indicated no impairment.

Although we cannot predict if or when goodwill may become impaired in the future, impairment charges may occur if we are unable to replace the value of our depleting asset base or if other adverse events (for example, lower sustained oil and gas prices) reduce the fair value of the associated reporting unit. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

Due to the inter−relationship of the various estimates involved in assessing goodwill for impairment, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates.

Production Imbalances

We have gas production imbalance positions that are the result of partial interest owners selling more or less than their proportionate share of gas on jointly owned wells. Imbalances are generally settled by disproportionate gas sales over the remaining life of the well, or by cash payment by the overproduced party to the underproduced party. We use the entitlement method of accounting for natural gas sales. Accordingly, revenue is deferred for gas deliveries in excess of our net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. Our net gas imbalances at December 31, 2009 and 2008, were immaterial.

Forward−Looking Statements

Certain information included in this annual report and other materials filed or to be filed by us with the Securities and Exchange Commission, as well as information included in oral statements or other written statements made or to be made by us, contain projections and forward−looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended, relating to our operations and the oil and gas industry. Such forward−looking statements may be or may concern, among other things, capital expenditures in total or by region, capital budget and funding thereof, cash flow, drilling activity, drilling locations, the number of wells to be drilled, worked over or recompleted in total or by region, acquisition and development activities and funding thereof, production and reserve growth, pricing differentials, reserve potential, operating costs, operating margins, production and exploration activities, oil, gas and natural gas liquids reserves and prices, hedging activities and the results thereof, liquidity, debt repayment, unused borrowing capacity, estimated stock award vesting periods, completion of pipelines and processing facilities, regulatory matters, competition and value of non−cash dividends. Such forward−looking statements are based on management's current plans, expectations, assumptions, projections and estimates and are identified by words such as "expects," "intends," "plans," "projects," "predicts," "anticipates," "believes," "estimates," "goal," "should," "could," "assume," and similar words that convey the uncertainty of future events. These statements are not guarantees of future performance and involve certain risks, uncertainties and assumptions that are difficult to predict. Therefore, actual results may differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward−looking statements. Some of the risk factors that could cause actual results to differ materially are discussed in Item 1A, Risk Factors.

Item 7A. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

We only enter derivative financial instruments in conjunction with our hedging activities. These instruments principally include commodity futures, collars, swaps and interest rate swap agreements. These financial and commodity−based derivative contracts are used to limit the risks of fluctuations in interest rates and natural gas, crude oil and natural gas liquids prices. Gains and losses on these derivatives are generally offset by losses and gains on the respective hedged exposures.

Our Board of Directors has adopted a policy governing the use of derivative instruments, which requires that all derivatives used by us relate to an underlying, offsetting position, anticipated transaction or firm commitment, and prohibits the use of speculative, highly complex or leveraged derivatives. Risk management programs using derivatives must be authorized by the Chairman of the Board and the President. These programs are also reviewed quarterly by our internal risk management committee and annually by the Board of Directors.

Hypothetical changes in interest rates and prices chosen for the following estimated sensitivity effects are considered to be reasonably possible near−term changes generally based on consideration of past fluctuations for each risk category. It is not possible to accurately predict future changes in interest rates and product prices. Accordingly, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Interest Rate Risk

We are exposed to interest rate risk on short−term and long−term debt carrying variable interest rates. At December 31, 2009, our variable rate debt had a carrying value of $1.2 billion, which approximated its fair value, and our fixed rate debt had a carrying value of $9.3 billion and an approximate fair value of $10.3 billion. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest cost, interest rate volatility and financing risk. This is accomplished through a mix of bank debt with short−term variable rates and fixed rate senior and subordinated debt, as well as the occasional use of interest rate swaps.

The following table shows the carrying amount and fair value of long−term debt and the hypothetical change in fair value that would result from a 100−basis point change in interest rates. Unless otherwise noted, the hypothetical change in fair value could be a gain or a loss depending on whether interest rates increase or decrease.

(in millions)	Carrying Amount	Fair Value *(a)*	Hypothetical Change in Fair Value
Total debt as of December 31, 2009	$(10,487)	$(11,526)	$ 704
Total debt as of December 31, 2008	$(11,959)	$(11,421)	$ 644

(a) Fair value is based upon current market quotes and is the estimated amount required to purchase our debt on the open market. This estimated value does not include any redemption premium.

Commodity Price Risk

We have hedged a portion of our price risks associated with our natural gas and crude oil sales. As of December 31, 2009, our outstanding futures contracts and swap agreements had a net fair value gain of $1.1 billion. The following table shows the fair value of our derivative contracts and the hypothetical change in fair value that would result from a 10% change in commodities prices or basis prices at December 31, 2009. The hypothetical change in fair value could be a gain or a loss depending on whether prices increase or decrease.

(in millions)	Fair Value	Hypothetical Change in Fair Value
Natural gas futures and sell basis swap agreements	$778	$ 299
Natural gas purchase basis swap agreements	$ 10	$ —
Crude oil futures and differential swaps	$329	$ 206

Because most of our futures contracts and swap agreements have been designated as hedge derivatives, changes in their fair value generally are reported as a component of accumulated other comprehensive income (loss) until the related sale of production occurs. At that time, the realized hedge derivative gain or loss is transferred to product revenues in the consolidated income statement. None of our derivative contracts have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date.

Item 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

The following financial statements and supplementary information are included under Item 15(a):

Item 9. ***CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE***

There have been no changes in accountants or any disagreements with accountants on any matter of accounting principles or practices or financial statement disclosures during the two years ended December 31, 2009.

Item 9A. ***CONTROLS AND PROCEDURES***

a) Evaluation of Disclosure Controls and Procedures

We performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures pursuant to Exchange Act Rules 13a−15 and 15d−15 as of the end of the period covered by this report. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in our periodic filings with the Securities and Exchange Commission and that our disclosure controls and procedures are effective to ensure that information required to be disclosed in Exchange Act reports is recorded, processed, summarized and reported within the specific time periods. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our Company have been detected.

b) Management's Report on Internal Control over Financial Reporting

Our management's report on internal control over financial reporting is set forth in Item 8 of this Annual Report on Form 10−K and is incorporated by reference herein.

c) Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting during the quarter ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. ***OTHER INFORMATION***

None.

PART III

Except for the portion of Item 10 relating to Executive Officers of the Registrant which is included in Part I of this Report or is included below, the information called for by Items 10 through 14 is incorporated by reference to the Proxy Statement or an amendment to this Annual Report on Form 10−K in Form 10−K/A to be filed with the Securities and Exchange Commission no later than April 30, 2010.

Item 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

We have a Code of Business Conduct and Ethics that applies to all directors, officers and employees, including the chief executive officer and senior financial officers. We also have a Code of Ethics for the Chief Executive Officer and Senior Financial Officers. You can find our Code of Business Conduct and Ethics and our Code of Ethics for the Chief Executive Officer and Senior Financial Officers on our web site at http://www.xtoenergy.com. You can also obtain a free copy of these materials by contacting us at 810 Houston Street, Fort Worth, Texas 76102, Attn: Corporate Secretary. Any amendments to or waivers from these codes that apply to our executive officers will be posted on the Company's web site or by other appropriate means in accordance with the rules of the Securities and Exchange Commission.

Item 11. *EXECUTIVE COMPENSATION*

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

Item 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE*

Item 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

PART IV

Item 15. ***EXHIBITS AND FINANCIAL STATEMENT SCHEDULES***

(a) The following documents are filed as a part of this report:

1. Financial Statements:

2. Financial Statement Schedules:

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes to consolidated financial statements

(b) Exhibits

See Index to Exhibits at page 96 for a description of the exhibits filed as a part of this report. Documents filed prior to June 1, 2001, were filed with the Securities and Exchange Commission under our prior name, Cross Timbers Oil Company.

XTO ENERGY INC.

Consolidated Balance Sheets

(in millions, except shares)	December 31 2009	2008
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 9**	$ 25
Accounts receivable, net	**965**	1,217
Derivative fair value	**1,222**	2,735
Current income tax receivable	**170**	57
Other	**182**	224
Total Current Assets	**2,548**	4,258
Property and Equipment, at cost—successful efforts method:		
Proved properties	**34,180**	30,994
Unproved properties	**3,691**	3,907
Other	**2,810**	2,239
Total Property and Equipment	**40,681**	37,140
Accumulated depreciation, depletion and amortization	**(8,747)**	(5,859)
Net Property and Equipment	**31,934**	31,281
Other Assets:		
Derivative fair value	**68**	1,023
Acquired gas gathering contracts, net of accumulated amortization	**97**	105
Goodwill	**1,475**	1,447
Other	**133**	140
Total Other Assets	**1,773**	2,715
TOTAL ASSETS	**$36,255**	$38,254
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 1,482**	$ 1,912
Payable to royalty trusts	**28**	13
Current maturities of long−term debt	**250**	—
Derivative fair value	**167**	35
Deferred income tax payable	**342**	940
Other	**32**	30
Total Current Liabilities	**2,301**	2,930
Long−term Debt	**10,237**	11,959
Other Liabilities:		
Derivative fair value	**6**	—
Deferred income taxes payable	**5,522**	5,200
Asset retirement obligation	**783**	735
Other	**80**	83
Total Other Liabilities	**6,391**	6,018
Commitments and Contingencies (Note 6)		
Stockholders' Equity:		
Common stock ($0.01 par value, 1,000,000,000 shares authorized, 589,361,021 and 585,094,847 shares issued)	**6**	6
Additional paid−in capital	**8,471**	8,315
Treasury stock, at cost (6,345,697 and 5,563,247 shares)	**(177)**	(147)
Retained earnings	**8,317**	6,588
Accumulated other comprehensive income (loss)	**709**	2,585
Total Stockholders' Equity	**17,326**	17,347
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$36,255**	$38,254

See accompanying notes to consolidated financial statements.

Table of Contents

XTO ENERGY INC.

Consolidated Income Statements

(in millions, except per share data)	Year Ended December 31 2009	2008	2007
REVENUES			
Gas and natural gas liquids	**$6,322**	$5,728	$4,214
Oil and condensate	**2,605**	1,796	1,204
Gas gathering, processing and marketing	**125**	168	100
Other	**12**	3	(5)
Total Revenues	**9,064**	7,695	5,513
EXPENSES			
Production	**999**	942	615
Taxes, transportation and other	**678**	703	444
Exploration	**77**	88	52
Depreciation, depletion and amortization	**3,079**	2,025	1,187
Accretion of discount in asset retirement obligation	**40**	31	22
Gas gathering and processing	**124**	101	81
General and administrative	**356**	382	231
Derivative fair value (gain) loss	**24**	(85)	(11)
Total Expenses	**5,377**	4,187	2,621
OPERATING INCOME	**3,687**	3,508	2,892
OTHER EXPENSE			
Interest expense, net	**524**	482	250
INCOME BEFORE INCOME TAX	**3,163**	3,026	2,642
INCOME TAX EXPENSE			
Current	**333**	140	292
Deferred	**811**	974	659
Total Income Tax Expense	**1,144**	1,114	951
NET INCOME	**$2,019**	$1,912	$1,691
EARNINGS PER COMMON SHARE			
Basic	**$ 3.48**	$ 3.58	$ 3.57
Diluted	**$ 3.46**	$ 3.54	$ 3.52
DIVIDENDS DECLARED PER COMMON SHARE	**$ 0.50**	$ 0.48	$0.408

See accompanying notes to consolidated financial statements.

XTO ENERGY INC.

Consolidated Statements of Comprehensive Income

(in millions)	Year Ended December 31 2009	2008	2007
Net Income	**$ 2,019**	$ 1,912	$1,691
Other comprehensive income (loss):			
Change in hedge derivative fair value	**1,213**	3,852	(126)
Realized (gain) loss on hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income (loss)	**(4,179)**	294	(701)
Net unrealized hedge derivative (loss) gain	**(2,966)**	4,146	(827)
Change in funded status of post−retirement plans	**5**	(9)	(8)
Realized loss on funded status of post−retirement plan reclassified into earnings from accumulated other comprehensive income (loss)	**5**	—	—
Total change in comprehensive (loss) income	**(2,956)**	4,137	(835)
Income tax benefit (expense)	**1,080**	(1,512)	309
Total other comprehensive (loss) income	**(1,876)**	2,625	(526)
Total comprehensive income	**$ 143**	$ 4,537	$1,165

See accompanying notes to consolidated financial statements.

XTO ENERGY INC.

Consolidated Statements of Cash Flows

(in millions)	Year Ended December 31 2009	2008	2007
OPERATING ACTIVITIES			
Net income	**$ 2,019**	$ 1,912	$ 1,691
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**3,079**	2,025	1,187
Accretion of discount in asset retirement obligation	**40**	31	22
Non−cash incentive compensation	**137**	170	65
Dry hole expense	**44**	22	21
Deferred income tax	**811**	974	659
Non−cash derivative fair value (gain) loss	**130**	(72)	43
Gain on extinguishment of debt	**(17)**	—	—
Other non−cash items	**(24)**	2	23
Changes in operating assets and liabilities, net of effects of acquisition of corporation *(a)*	**(265)**	171	(72)
Cash Provided by Operating Activities	**5,954**	5,235	3,639
INVESTING ACTIVITIES			
Proceeds from sale of property and equipment	**3**	24	1
Property acquisitions, including acquisition of corporation	**(264)**	(8,456)	(4,012)
Development costs, capitalized exploration costs and dry hole expense	**(3,190)**	(3,661)	(2,668)
Other property and asset additions	**(606)**	(913)	(666)
Cash Used by Investing Activities	**(4,057)**	(13,006)	(7,345)
FINANCING ACTIVITIES			
Proceeds from long−term debt	**7,730**	19,560	7,293
Payments on long−term debt	**(9,183)**	(14,250)	(4,433)
Net proceeds from common stock offerings	**—**	2,612	1,009
Dividends	**(287)**	(250)	(170)
Debt costs	**(2)**	(32)	(18)
Proceeds from exercise of stock options and warrants	**23**	23	33
Payments upon exercise of stock options	**(23)**	(70)	(57)
Excess tax benefit on exercise of stock options or vesting of stock awards	**20**	64	57
Other, primarily (decrease) increase in cash overdrafts	**(191)**	139	(13)
Cash (Used) Provided by Financing Activities	**(1,913)**	7,796	3,701
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(16)**	25	(5)
Cash and Cash Equivalents, January 1	**25**	—	5
Cash and Cash Equivalents, December 31	**$ 9**	$ 25	$ —
***(a)* Changes in Operating Assets and Liabilities**			
Accounts receivable	**$ 258**	$ (151)	$ (198)
Other current assets	**(71)**	(32)	(85)
Other operating assets and liabilities	**(21)**	(7)	(9)
Current liabilities	**22**	(92)	220
Change in current assets from early settlement of hedges, net of amortization	**(453)**	453	—
	$ (265)	$ 171	$ (72)

See accompanying notes to consolidated financial statements.

XTO ENERGY INC.

Consolidated Statements of Stockholders' Equity

(in millions, except per share amounts)	Common Stock	Additional Paid−in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balances, December 31, 2006	$ 5	$ 2,057	$ (125)	$ 3,442	$ 486	$ 5,865
Net income	—	—	—	1,691	—	1,691
Other comprehensive loss	—	—	—	—	(526)	(526)
Issuance/vesting of stock awards, including income tax benefits	—	26	(9)	—	—	17
Expensing of stock options	—	42	—	—	—	42
Stock option and warrant exercises, including income tax benefits	—	38	—	—	—	38
Common stock offering	—	1,009	—	—	—	1,009
Common stock dividends ($0.408 per share)	—	—	—	(195)	—	(195)
Balances, December 31, 2007	5	3,172	(134)	4,938	(40)	7,941
Net income	—	—	—	1,912	—	1,912
Other comprehensive income	—	—	—	—	2,625	2,625
Issuance/vesting of stock awards, including income tax benefits	—	89	(13)	—	—	76
Expensing of stock options	—	80	—	—	—	80
Stock option and warrant exercises, including income tax benefits	—	25	—	—	—	25
Issuance of common stock for acquisition of corporation or properties	—	2,338	—	—	—	2,338
Common stock offering	1	2,611	—	—	—	2,612
Common stock dividends ($0.48 per share)	—	—	—	(262)	—	(262)
Balances, December 31, 2008	6	8,315	(147)	6,588	2,585	17,347
Net income	—	—	—	2,019	—	2,019
Other comprehensive loss	—	—	—	—	(1,876)	(1,876)
Issuance/vesting of stock awards, including income tax benefits	—	102	(30)	—	—	72
Expensing of stock options	—	43	—	—	—	43
Stock option and warrant exercises, including income tax benefits	—	11	—	—	—	11
Common stock dividends ($0.50 per share)	—	—	—	(290)	—	(290)
Balances, December 31, 2009	$ 6	$ 8,471	$ (177)	$ 8,317	$ 709	$ 17,326

See accompanying notes to consolidated financial statements.

XTO ENERGY INC.

Notes to Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

XTO Energy Inc., a Delaware corporation, was organized under the name Cross Timbers Oil Company in October 1990 to ultimately acquire the business and properties of predecessor entities that were created from 1986 through 1989. Cross Timbers Oil Company completed its initial public offering of common stock in May 1993 and changed its name to XTO Energy Inc. in June 2001.

On December 13, 2009, we entered into a definitive merger agreement with Exxon Mobil Corporation under which we would become a wholly owned subsidiary of ExxonMobil. As a result of the merger, each outstanding share of our common stock will be converted into 0.7098 shares of ExxonMobil common stock. Completion of the merger remains subject to certain conditions, including the adoption of the merger agreement by our stockholders, as well as certain governmental and regulatory approvals. We currently expect to complete the merger in the second quarter of 2010, however, no assurance can be given as to when, or if, the merger will occur.

The accompanying consolidated financial statements include the financial statements of XTO Energy Inc. and all of its wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts presented in prior period financial statements have been reclassified for consistency with current period presentation.

We are an independent oil and gas company with production and exploration concentrated in the southwestern and central United States. We also have international operations located in the North Sea that do not have a material impact on either our financial position or earnings. Additionally, we gather, process and market gas, transport and market oil and conduct other activities directly related to our oil and gas producing activities.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. Significant items subject to such estimates and assumptions include the following:

- estimates of proved reserves and related estimates of the present value of future revenues;
- the carrying value of oil and gas properties;
- asset retirement obligations;
- income taxes;
- derivative financial instruments;
- obligations related to employee benefits; and
- legal and environmental risks and exposure.

Property and Equipment

We follow the successful efforts method of accounting, capitalizing costs of successful exploratory wells and expensing costs of unsuccessful exploratory wells. Exploratory geological and geophysical costs are expensed as incurred. All developmental costs are capitalized. We generally pursue acquisition and development of proved reserves as opposed to exploration activities. A significant portion of the property costs reflected in the accompanying consolidated balance sheets are from acquisitions of proved and unproved properties from other oil and gas companies. Proved properties balances include costs of $923 million at December 31, 2009 and $1.4 billion at December 31, 2008 related to wells in process of drilling. Successful drill well costs are transferred to proved properties generally within one month of the well completion date. Inventory held for future use on our producing properties totaled $147 million at December 31, 2009 and $182 million at December 31, 2008, and is included in other current assets on the consolidated balance sheet.

Depreciation, depletion and amortization (DD&A) of proved producing properties is computed on the unit−of−production method based on estimated proved oil and gas reserves. Other property and equipment is generally depreciated using either the unit−of−production method for assets associated with specific reserves or the straight−line method over estimated useful lives which range from 3 to 40 years. Repairs and maintenance are expensed, while renewals and betterments are generally capitalized.

If conditions indicate that producing properties may be impaired, the carrying value of property is compared to management's future estimated pre−tax cash flow from properties generally aggregated on a field−level basis. If impairment is necessary, the asset carrying value is written down to fair value. Cash flow pricing estimates are based on estimated reserves and production information and pricing assumptions that management believes are reasonable. We recognized an impairment of proved properties of $128 million in 2008.

Impairment of individually significant unproved properties is assessed on a property−by−property basis using an impairment analysis similar to the proved property model discussed above. Impairment of other unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. We recognized in DD&A an impairment of unproved properties of $247 million in 2009, $156 million in 2008 and $49 million in 2007.

Asset Retirement Obligation

If the fair value for asset retirement obligation can be reasonably estimated, the liability is recognized in the period when it is incurred. Oil and gas producing companies incur this liability upon acquiring or drilling a well. The retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with an offsetting increase to proved properties on the balance sheet. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement. See Note 5.

Royalty Trusts

We created Cross Timbers Royalty Trust in February 1991 and Hugoton Royalty Trust in December 1998 by conveying defined net profits interests in certain of our properties. Units of both trusts are traded on the New York Stock Exchange. We make monthly net profits payments to each trust based on revenues and costs from the related underlying properties. Amounts due the trusts are deducted from our revenues, taxes, production expenses and development costs. We no longer have any ownership interest in these trusts.

Cash and Cash Equivalents

Cash equivalents are considered to be all highly liquid investments having an original maturity of three months or less.

Income Taxes

We record deferred income tax assets and liabilities to recognize timing differences between recognition of income for financial statement and income tax reporting purposes. Deferred income tax assets are calculated using enacted tax rates for each jurisdiction applicable to taxable income in the years when we anticipate these timing differences will reverse. The effect of changes in tax rates is recognized in the period of enactment.

Financial statement recognition of a tax position is dependent on an assessment of a 50% or greater likelihood that the tax position will be sustained upon examination, based on the technical merits of the position. Any interest and penalties related to uncertain tax positions are recorded as interest expense and general and administrative expense, respectively. See Note 4.

Other Assets

Other assets primarily include deferred debt costs that are amortized to interest expense over the term of the related debt (Note 3) and the long−term portion of gas balancing receivable (see *Revenue Recognition and Gas Balancing* below). Other assets are presented net of accumulated amortization of $39 million at December 31, 2009 and $31 million at December 31, 2008.

We determined that a portion of the purchase price of the 2005 Antero Resources Corporation acquisition was allocable to gas gathering contracts and goodwill. Gas gathering contracts are associated with the pipeline acquired, and the value of $140 million was determined based on the estimated discounted cash flows from those contracts. The gas gathering contracts are amortized, as a component of depreciation, depletion and amortization expense, on a unit−of−production basis using the estimated proved reserves of the related Barnett Shale properties. Accumulated amortization of acquired gas gathering contracts was $43 million as of December 31, 2009 and $35 million as of December 31, 2008. Amortization expense is expected to be approximately $6 million to $7 million annually from 2010 through 2014, depending on Barnett Shale production.

Goodwill of $1.5 billion represents the excess of the purchase price paid for Hunt Petroleum Corporation (Note 14) and Antero Resources over their respective fair value of the assets acquired and liabilities assumed. Goodwill is not amortized, but instead is subject to an annual assessment of impairment based on a fair value test performed as of October 1. The annual test indicated no impairment.

Derivatives

We use derivatives to hedge against changes in cash flows related to product price and interest rate risks, as opposed to their use for trading purposes. We record all derivatives on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The fair value of call options and collars are generally determined under the Black−Scholes option−pricing model. Most values are confirmed by counterparties to the derivative.

Realized and unrealized gains and losses on derivatives that are not designated as hedges, as well as on the ineffective portion of hedge derivatives, are recorded as a derivative fair value gain or loss in the income statement. Unrealized gains and losses on effective cash flow hedge derivatives, as well as any deferred gain or loss realized upon early termination of effective hedge derivatives, are recorded as a component of accumulated other comprehensive income (loss). When the hedged transaction occurs, the realized gain or loss, as well as any deferred gain or loss, on the hedge derivative is transferred from accumulated other comprehensive income (loss) to earnings. Realized gains and losses on commodity hedge derivatives are recognized in oil and gas revenues, and realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Settlements of derivatives are included in cash flows from operating activities.

To summarize, we record our derivatives at fair value in our consolidated balance sheets. Gains and losses resulting from changes in fair value and upon settlement are reported as follows:

Derivative Type	Fair Value Gains/Losses	Financial Statement Reporting
Non−hedge derivatives and Hedge derivatives— ineffective portion	Unrealized and Realized	Reported in the Consolidated Income Statements as derivative fair value (gain) loss
Hedge derivatives— effective portion	Unrealized	Reported in Stockholders' Equity in the Consolidated Balance Sheets as accumulated other comprehensive income (loss)
	Realized	Reported in the Consolidated Income Statements and classified based on the hedged item (e.g., gas revenue, oil revenue or interest expense)

To designate a derivative as a cash flow hedge, we document at the hedge's inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative's term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as oil or gas revenue or interest expense when the underlying transaction occurs. If it is determined that the designated hedge transaction is not probable to occur, any unrealized gains or losses are recognized immediately in the income statement as a derivative fair value gain or loss. During 2009, 2008 and 2007, there were no gains or losses reclassified into earnings as a result of the discontinuance of hedge accounting treatment for any of our derivatives.

Physical delivery contracts that are not expected to be net cash settled are deemed to be normal sales. However, physical delivery contracts that have a price not clearly and closely associated with the asset sold are not a normal sale and must be accounted for as a non−hedge derivative.

Revenue Recognition and Gas Balancing

Oil, gas and natural gas liquids revenues are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectibility of the revenue is reasonably assured. At times we may sell more or less than our entitled share of gas production. When this happens, we use the entitlement method of accounting for gas sales, based on our net revenue interest in production. Accordingly, revenue is deferred for gas deliveries in excess of our net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. Our net gas imbalances at December 31, 2009 and 2008, were immaterial.

Gas Gathering, Processing and Marketing Revenues

We market our gas, as well as some gas produced by third parties, to brokers, local distribution companies and end−users. Gas gathering and marketing revenues are recognized in the month of delivery based on customer nominations and adjusted based on actual deliveries. Gas processing and marketing revenues are recorded net of cost of gas sold of $809 million in 2009, $872 million for 2008 and $517 million for 2007. These amounts are net of intercompany eliminations.

Other Revenues

Other revenues result from and are related to our ongoing major operations. These revenues include dividends, foreign currency transaction adjustments, and various gains and losses, including from lawsuits and other disputes, as well as from non−significant sales of property and equipment.

Loss Contingencies

When management determines that it is probable that an asset has been impaired or a liability has been incurred, we accrue our best estimate of the loss if it can be reasonably estimated. Our legal costs related to litigation are expensed as incurred. See Note 6.

Interest

Interest expense includes amortization of deferred debt costs and is presented net of interest income of $1 million in 2009, $13 million in 2008 and $17 million in 2007, and net of capitalized interest of $42 million in 2009, $39 million in 2008 and $30 million in 2007. Interest is capitalized as proved property cost based on the weighted average interest rate and the cost of wells in process of drilling. Included in accounts payable and accrued liabilities is accrued interest of $132 million at December 31, 2009 and $139 million at December 31, 2008.

Stock−Based Compensation

We recognize compensation related to all stock−based awards, including stock options, in the financial statements based on their estimated grant−date fair value. We estimate expected forfeitures and we recognize compensation expense only for those awards expected to vest. Compensation expense is amortized over the estimated service period, which is the shorter of the award's time vesting period or the derived service period as implied by any accelerated vesting provisions when the common stock price reaches specified levels. All compensation must be recognized by the time the award vests. See Note 13.

Earnings per Common Share

We report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities unless their impact is antidilutive. See Note 10.

Segment Reporting

We evaluated how the Company is organized and managed and have identified only one operating segment, which is the exploration and production of oil, natural gas and natural gas liquids. We consider our gathering, processing and marketing functions as ancillary to our oil and gas producing activities. Substantially all of our assets are located in the United States, and substantially all revenues are attributable to United States customers. Our North Sea assets and revenues comprised approximately 1% of total consolidated assets as of December 31, 2009 and less than 1% of total consolidated revenues for the year ended December 31, 2009.

Our production is sold to various purchasers, based on their credit rating and the location of our production. For the year ended December 31, 2009, no single purchaser comprised more than 10% of total revenues. For the year ended December 31, 2008, sales to one purchaser were approximately 16% of total revenues. For the year ended December 31, 2007, sales to each of two purchasers were approximately 18% and 11% of total revenues. We believe that alternative purchasers are available, if necessary, to purchase production at prices substantially similar to those received from these significant purchasers.

New Accounting Pronouncements

In May 2009, we adopted the authoritative guidance of accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We have evaluated subsequent events through February 24, 2010.

2. Related Party Transactions

Jack Randall, one of our nonemployee directors, was a co−founder and director of Randall & Dewey Partners, L.P., which was acquired by Jefferies Group, Inc. in 2005 and now operates as Jefferies & Company, Inc. Jefferies served as one of our financial advisors in connection with the announced merger with ExxonMobil. If the merger is completed, we have agreed to pay Jefferies a transaction fee of $24 million. In addition, we agreed to reimburse Jefferies for all reasonable and documented out−of−pocket expenses, including legal fees, incurred in connection with the services it provides to us in connection with the merger and have agreed to indemnify Jefferies against certain liabilities. In addition, Jefferies performed property acquisition advisory services for us in prior years. A division of Jefferies also performed co−manager services on our February and August 2008 and June 2007 common stock offerings and our April and July 2008 and July and August 2007 senior note offerings. We paid, for the credit of Jefferies, total fees of $11.8 million in 2008 and $3.4 million in 2007. There were no amounts payable at December 31, 2009 or 2008.

In February 2007, in recognition of the Chairman of the Board and Founder and as part of a charitable giving program to support higher education, the Board of Directors approved a conditional contribution of $6.8 million to assist in building an athletics and academic center at Baylor University. This contribution was paid in two equal installments of $3.4 million. The first payment was made May 2007 and the second was paid in July 2008. Since this was a conditional contribution, the first payment was included as general and administrative expense in 2007, and the second payment was included in general administrative expense when the condition was satisfied in second quarter 2008. Concurrently, our Chairman of the Board and Founder, made a $3.2 million pledge for the same project. He fulfilled his obligation in 2008. In return for these contributions, we, along with our Chairman of the Board and Founder, obtained naming rights for the building and certain facilities within the building.

In November 2007, the Board of Directors approved and we paid our Chairman of the Board and Founder $150,000 for an easement across his property in North Texas plus an additional $36,000 for damages. The easement was for approximately 10,000 feet at the standard easement rate in the area of $15 per foot.

Table of Contents

3. Debt

(in millions)	December 31 2009	December 31 2008
Bank debt:		
Commercial paper, 0.3% at December 31, 2009 and 3.0% at December 31, 2008	$ 622	$ 72
Revolving credit facility due April 1, 2013, 2. 4% at December 31, 2008	—	1,825
Term loan due April 1, 2013, 0.7% at December 31, 2009 and 1.9% at December 31, 2008	500	500
Term loan due February 5, 2013, 0.6% at December 31, 2009 and 2.3% at December 31, 2008	100	100
Senior notes:		
5.00%, due August 1, 2010	250	250
7.50%, due April 15, 2012	350	350
5.90%, due August 1, 2012	550	550
6.25%, due April 15, 2013	400	400
4.625%, due June 15, 2013	400	400
5.75%, due December 15, 2013	500	500
4.90%, due February 1, 2014	500	500
5.00%, due January 31, 2015	348	350
5.30%, due June 30, 2015	400	400
5.65%, due April 1, 2016	400	400
6.25%, due August 1, 2017	735	750
5.50%, due June 15, 2018	773	800
6.50%, due December 15, 2018	1,000	1,000
6.10%, due April 1, 2036	591	600
6.75%, due August 1, 2037	1,399	1,450
6.375%, due June 15, 2038	704	800
Net discount on senior notes	(35)	(38)
Total debt	10,487	11,959
Less current portion	(250)	—
Long−term debt	$10,237	$11,959

Because we had both the intent and ability to refinance the commercial paper balance outstanding with borrowings under our revolving credit facility due in April 2013, we have classified these borrowings as long−term debt in our consolidated balance sheets. Before the stated maturities of April 2013, we may renegotiate the revolving credit agreement and term loans to increase the borrowing commitment and/or extend the maturity. Maturities of long−term debt as of December 31, 2009, excluding net discounts, are as follows:

(in millions)	
2010	$ 250
2011	—
2012	900
2013	2,522
2014	500
Remaining	6,350
Total	$10,522

Commercial Paper

Our commercial paper program availability is $2.84 billion. Borrowings under the commercial paper program reduce our available capacity under the revolving credit facility on a dollar−for−dollar basis. The commercial paper borrowings may have terms up to 397 days and bear interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. On December 31, 2009, borrowings under our commercial paper program were $622 million at a weighted average interest rate of 0.3%. The weighted average interest rate on commercial paper borrowings was 0.6% during 2009.

Bank Debt

On December 31, 2009, we had no borrowings under our revolving credit agreement with commercial banks, and we had available borrowing capacity of $2.22 billion net of our commercial paper borrowings. We use the facility for general corporate purposes and as a backup facility for our commercial paper program. We have the option, with bank approval, to increase the commitment up to an additional $660 million. The interest rate on any borrowing is generally based on LIBOR plus 0.40%. When utilization of available commitments is greater than 50%, then the interest rate on our borrowings is increased by 0.05%. Interest is paid at maturity, or quarterly if the term is for a period of 90 days or more. We also incur a commitment fee on unused borrowing commitments, which is 0.09%. The agreement requires us to maintain a debt−to−total capitalization ratio of not more than 65%. The weighted average interest rate on revolver borrowings was 1.7% until all outstanding borrowings were repaid in mid−January 2009.

In February 2008, we amended our $300 million term loan credit agreement to increase outstanding borrowings to $500 million and to extend the maturity date to April 1, 2013. The proceeds were used for general corporate purposes. The weighted average interest rate on this term loan borrowing was 0.8% during 2009.

Additionally in February 2008, we borrowed $100 million under a five−year unsecured term loan agreement in a single advance that matures February 5, 2013. The proceeds were used for general corporate purposes. The weighted average interest rate on this term loan borrowing was 0.7% during 2009.

We have unsecured and uncommitted lines of credit with commercial banks totaling $100 million. As of December 31, 2009, there were no borrowings under these lines.

Repurchase of Senior Notes

In 2009, we repurchased $200 million total face amount of senior notes, including $2 million of our 5.00% senior notes due 2015, $15 million of our 6.25% senior notes due 2017, $27 million of our 5.50% senior notes due 2018, $9 million of our 6.10% senior notes due 2036, $51 million of our 6.75% senior notes due 2037 and $96 million of our 6.375% senior notes due 2038. In connection with these repurchases, we recognized a $17 million gain on extinguishment of debt, net of unamortized discounts and the write−off of deferred debt offering costs. These gains were netted against interest expense in the consolidated income statements.

Senior Notes

In July 2007, we sold $300 million of 5.9% senior notes due August 1, 2012, $450 million of 6.25% senior notes due August 1, 2017 and $500 million of 6.75% senior notes due August 1, 2037. In August 2007, we sold an additional $250 million of the 5.9% senior notes, $300 million of the 6.25% senior notes and $450 million of the 6.75% senior notes that constituted a further issuance of the senior notes issued in July 2007. Together, the 5.9% senior notes were issued at 100.585% of par to yield 5.761% to maturity. The 6.25% senior notes were issued at 100.419% of par to yield 6.193% to maturity. The 6.75% senior notes were issued at 100.022% of par to yield 6.748% to maturity. Interest is payable on each series of notes on February 1 and August 1 of each year, beginning February 1, 2008. Net proceeds of $2.24 billion were used to fund a portion of the acquisition of properties from Dominion Resources, Inc. (Note 14) and to pay down outstanding commercial paper borrowings.

In April 2008, we sold $400 million of 4.625% senior notes due June 15, 2013, $800 million of 5.50% senior notes due June 15, 2018 and $800 million of 6.375% senior notes due June 15, 2038. The 4.625% senior notes were issued at 99.888% of par to yield 4.651% to maturity. The 5.50% senior notes were issued at 99.539% of par to yield 5.561% to maturity. The 6.375% senior notes were issued at 99.864% of par to yield 6.386% to maturity. Net proceeds of $1.98 billion were used to fund property acquisitions that closed during the second and third quarters of 2008 (Note 14), to pay down outstanding commercial paper borrowings and for general corporate purposes.

In August 2008, we sold $250 million of 5.00% senior notes due August 1, 2010, $500 million of 5.75% senior notes due December 15, 2013, $1.0 billion of 6.50% senior notes due December 15, 2018 and $500 million of 6.75% senior notes due August 1, 2037. The notes due 2037 constitute a further issuance of the 6.75% senior notes issued in July 2007. The 5.00% senior notes were issued at 99.988% of par to yield 5.007% to maturity. The 5.75% senior notes were issued at 99.931% of par to yield 5.767% to maturity. The 6.50% senior notes were issued at 99.713% of par to yield 6.540% to maturity. The 6.75% senior notes were issued at 94.391% of par to yield 7.214% to maturity. Net proceeds of $2.2 billion were used to partially fund the cash portion of the Hunt acquisition (Note 14).

The senior notes require no sinking fund. We may redeem all or a part of the senior notes at any time at a price of 100% of their principal balance plus accrued interest and a make−whole premium payment. The make−whole premium is calculated as any excess over the principal balance of the present value of remaining principal and interest payments at the U.S. Treasury rate for a comparable maturity plus no more than 0.375%.

If we are the subject of a change in control, such as the proposed merger with ExxonMobil, we are required to offer to purchase at 101% of par our 7.50% senior notes due 2012 and our 6.25% senior notes due 2013. Our other senior notes are not subject to this provision.

4. Income Tax

The following reconciles our income tax expense to the amount calculated at the statutory federal income tax rate:

(in millions)	**2009**	**2008**	**2007**
Income tax expense at the federal statutory rate (35%)	$1,107	$1,059	$925
State and local income taxes and other	37	55	26
Income tax expense	$1,144	$1,114	$951

Components of income tax expense are as follows:

(in millions)	**2009**	**2008**	**2007**
Current income tax *(a)*	$ 333	$ 140	$292
Deferred income tax	811	974	659
Income tax expense	$1,144	$1,114	$951

(a) The current income tax provision exceeds cash tax expense by the benefit realized upon exercise of stock options or vesting of stock awards in excess of amounts expensed in the financial statements. This benefit, which is recorded in additional paid−in capital, was $20 million in 2009, $69 million in 2008 and $64 million in 2007.

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and tax bases of assets and liabilities. Our net deferred tax assets and liabilities are recorded as a current liability of $342 million and a long−term liability of $5.5 billion at December 31, 2009 and as a current

Table of Contents
liability of $940 million and a long−term liability of $5.2 billion at December 31, 2008. Significant components of net deferred tax assets and liabilities are:

(in millions)	December 31 2009	December 31 2008
Deferred tax assets:		
Derivative fair value loss	$ 63	$ 13
Alternative minimum tax credit carryforwards	14	40
Stock incentive compensation	84	76
Other	45	45
Total deferred tax assets	206	174
Deferred tax liabilities:		
Property and equipment	(5,553)	(4,897)
Derivative fair value gain	(461)	(1,376)
Other	(56)	(41)
Total deferred tax liabilities	(6,070)	(6,314)
Net deferred tax liabilities	$(5,864)	$(6,140)

We had estimated tax loss carryforwards of $43 million at December 31, 2009 and $36 million at December 31, 2008 related to our United Kingdom subsidiary acquired from Hunt Petroleum (Note 14). A valuation allowance for the full amount of these carryforwards has been recorded.

As of December 31, 2009 and 2008, we did not have any unrecognized tax benefits. As a result, the only differences between our financial statements and our income tax returns relate to normal timing differences such as depreciation, depletion and amortization, which are recorded as deferred taxes on our consolidated balance sheets.

In 2007, the Internal Revenue Service completed its examination of our federal income tax returns for 2003 and 2004. Additional federal tax resulting from this examination was fully accrued in prior years. Under the terms of the final settlement with the IRS, we incurred immaterial interest expense and no penalties. Subsequent amendment of our state tax returns for these years did not have a significant effect on our results of operations or financial position. Tax years 2003 and 2004 remain subject to examination by state jurisdictions, and subsequent years are open to both federal and state examination.

5. Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state, federal and international laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The following is a summary of asset retirement obligation activity for the years ended December 31, 2009 and 2008:

(in millions)	2009	2008
Asset retirement obligation, January 1	$759	$453
Revisions in the estimated cash flows	(7)	52
Liability incurred upon acquiring and drilling wells	47	235
Liability settled upon plugging and abandoning wells	(27)	(12)
Accretion of discount expense	40	31
Asset retirement obligation, December 31	812	759
Less current portion	(29)	(24)
Asset retirement obligation, long term	$783	$735

6. Commitments and Contingencies

Leases

We lease compressors, offices, vehicles, aircraft and certain other equipment in our primary locations under noncancelable operating leases. Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. As of December 31, 2009, minimum future lease payments for all noncancelable lease agreements were as follows:

(in millions)	
2010	$ 29
2011	23
2012	14
2013	8
2014	3
Remaining	—
Total	$ 77

Amounts expensed under operating leases (including renewable monthly leases) were $101 million in 2009, $86 million in 2008 and $57 million in 2007.

Purchase Commitments

As of December 31, 2009, we have contracts with various providers to purchase compressors. These future commitments will result in expected payments of $30 million in 2010.

Transportation Contracts

We have entered firm transportation contracts with various pipelines. Under these contracts we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. Our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. We have generally delivered at least minimum volumes under our firm transportation contracts, therefore avoiding payment for deficiencies. As of December 31, 2009, maximum commitments under our transportation contracts were as follows:

(in millions)	
2010	$ 210
2011	224
2012	226
2013	221
2014	217
Remaining	756
Total	$1,854

In November 2008, we completed an agreement to enter into a twelve−year firm transportation contract, contingent upon obtaining regulatory approvals and completion of a new pipeline that connects the Fayetteville Shale to ANR Pipeline and Trunkline Pipeline in Quitman County, Mississippi. Upon the pipeline’s completion, currently expected in fourth quarter 2010, we will transport gas volumes for a transportation fee of up to $1.25 million per month plus fuel, currently expected to be 0.86% of the sales price. The potential effect of this agreement is not included in the above summary of our transportation contract commitments since our commitment is contingent upon completion of the indicated project.

Employment Agreements

The Company has entered into employment agreements with Messrs. Simpson, Hutton and Vennerberg. Each agreement is for a one−year term, which automatically continues year to year thereafter unless terminated by either party upon thirty days written notice prior to each November 30. Mr. Simpson is to receive an annual base salary of $3,600,000. He is not eligible to participate in the Company's cash bonus program. On the first business day of January during the term of his agreement, he will be entitled to receive grants of 110,000 shares of common stock with no vesting criteria and 40,000 performance shares that will have vesting criteria set by the Compensation Committee at the time of grant. In September 2009, the compensation committee approved an amendment to Mr. Simpson's employment agreement to provide that in the event of a change in control, he will receive a cash payment equal to three times the value of his annual stock awards based on the value of the stock on the date of the change in control in addition to other payments he would receive upon a change in control. The employment agreements with Messrs. Hutton and Vennerberg provide for minimum base salaries of $1,400,000 and $900,000, respectively. The Compensation Committee has authority to pay base salaries in excess of the minimum base salaries provided for in the agreements. The agreements also provide that, in the event (i) the officer terminates his employment for good reason, as defined in the agreement, (ii) we terminate the employee without cause, (iii) the officer dies or becomes disabled, or (iv) a change in control of the Company occurs, the officer is entitled to a lump−sum payment of three times the officer's most recent annual compensation, including bonuses. In addition, Messrs. Hutton and Vennerberg are entitled to receive a payment sufficient to make the officer whole for any excise tax on excess parachute payments imposed by the Internal Revenue Code. Mr. Simpson's employment agreement provides that the total aggregate payments to be made under the employment agreement and any other agreement providing payments upon a change in control be reduced to the maximum amount that can be paid without the imposition of the excise tax. In December 2009, the compensation committee approved amendments to the employment agreements of Messrs. Hutton and Vennerberg to eliminate the requirement to pay minimum bonus amounts equal to their annual base salaries and to remove the annual cap on total cash compensation they could receive each year paid in the form of salary and bonuses. Prior to the amendment, the annual cap on total cash compensation for Messrs. Hutton and Vennerberg was $12,500,000 and $7,500,000, respectively.

Upon retirement, each of these officers will enter into an eighteen−month consulting agreement under which the officer will receive a monthly payment based on his annual salary at the time of retirement, plus $10,000 a month for expenses. The officer will also become fully vested in any outstanding share−based awards unless otherwise provided in the award agreement.

Commodity Commitments

We have entered into futures contracts and swap agreements that effectively fix natural gas and crude oil prices. See Note 8.

Drilling Contracts

As of December 31, 2009, we have contracts with various drilling contractors to use 50 drilling rigs with terms of up to three years and minimum future commitments of $104 million in 2010, $23 million in 2011 and $2 million in 2012. Early termination of these contracts at December 31, 2009 would have required us to pay maximum penalties of $66 million. Based upon our planned drilling activities, we do not expect to pay significant early termination penalties.

Litigation

In July 2005 a predecessor company that we acquired, Antero Resources Corporation, was served with a lawsuit styled *Threshold Development Company, et al. v. Antero Resources Corp.*, which lawsuit was filed in the

District Court of Wise County, Texas. The plaintiffs are surface owners, royalty owners and prior working interest owners in several oil and gas leases as well as parties to other contractual agreements under which Antero Resources Corporation owned an interest. Antero Resources Corporation, the defendant, was acquired by us on April 1, 2005. The claims related to alleged events pre−dating the acquisition and concern non−payment of royalties, improper calculation of royalties, improper pricing related to royalties, trespass, failure to develop and breach of contract. We settled all claims related to the payment of royalties and trespass. Under the remaining claims, the plaintiffs sought both damages and termination of the existing oil and gas leases covering their interests. In October 2008, the trial court granted our motion for summary judgment, resulting in the dismissal of the plaintiffs' remaining claims. The plaintiffs have appealed the court's judgment. Based on a review of the current facts and circumstances with counsel, management has provided for what is believed to be a reasonable estimate of the loss exposure for this matter. While acknowledging the uncertainties of litigation, management believes that the ultimate outcome of this matter will not have a material effect on our earnings, cash flows or financial position.

In November 2008, an action was filed against the Company and our directors styled *Freedman v. Adams, et al*. in the Delaware Court of Chancery. The plaintiff is alleged to be a stockholder and brings the suit as a derivative action on behalf of the Company. The plaintiff seeks an equitable accounting for the alleged losses by the Company and injunctions mandating that a Section 162(m) plan be submitted to our stockholders for their approval and against further non−deductible payments, along with an award of accountants', experts' and attorneys' fees. We have filed a motion to dismiss. While we did not have in place a Section 162(m) plan at the time the suit was filed for cash payments, the Board of Directors approved a Section 162(m) plan in February 2009 that was approved by our stockholders at our annual meeting in May 2009. Although we are unable to predict the final outcome of this case, we believe that the allegations of this lawsuit are without merit, and we intend to vigorously defend the action.

In September 2008, a class action lawsuit was filed against the Company styled *Wallace B. Roderick Revocable Living Trust, et al. v. XTO Energy Inc.* in the District Court of Kearny County, Kansas. We removed the case to federal court in Wichita, Kansas. The plaintiffs allege that we have improperly taken post−production costs from royalties paid to the plaintiffs from wells located in Kansas, Oklahoma, and Colorado. The plaintiffs also seek to represent all royalty owners in these three states as a class. We have answered, denying all claims, and have filed motions to dismiss a portion of the claims. The federal court recently granted our motion for summary judgment concerning prior settled class actions that overlap plaintiff's proposed class action. The court also granted our motion to dismiss those portions of plaintiff's class that are currently being prosecuted in another case. Based on a review of the current facts and circumstances with counsel, management has provided for what is believed to be a reasonable estimate of the loss exposure for this matter. While acknowledging the uncertainties of litigation, management believes that the ultimate outcome of this matter will not have a material effect on our earnings, cash flows or financial position.

On December 14, 2009, Exxon Mobil Corporation and XTO Energy announced that the companies had entered into a definitive agreement under which we would become a wholly owned subsidiary of ExxonMobil. As a result of this announcement, a number of putative shareholder class actions have been filed, alleging breaches of fiduciary duties by the individual members or our Board of Directors. Each lawsuit generally seeks, among other things, declaratory and injunctive relief concerning the alleged fiduciary breaches, injunctive relief prohibiting the defendants from consummating the merger, imposition of constructive trusts in favor of plaintiffs and putative class members and unspecified monetary damages. Several putative shareholders have also filed an individual lawsuit in federal court alleging violations of the federal securities laws based on alleged false and material misrepresentations or omissions in the preliminary proxy filed with the Securities and Exchange Commission in connection with the proposed merger. The federal individual action also seeks to enjoin the proposed merger.

Two putative shareholder class actions were filed in the Delaware Court of Chancery between December 17, 2009 and December 18, 2009. Those cases are styled as (i) *Teamsters Allied Benefit Funds, et al. v. XTO Energy*

Inc., et al., Case No. 5150, filed on December 17, 2009 and (ii) *Nicholas Lombardi v. XTO Energy Inc., et al., Case No. 5152, filed on December 18, 2009*. On December 22, 2009, the Delaware Court of Chancery entered an order consolidating the complaints filed as of that date under the caption *In re XTO Energy Inc. Shareholders Litigation*.

Eleven putative shareholder class actions were filed in the District Courts of Tarrant County, Texas between December 14, 2009, and January 6, 2010. Those cases are styled: (i) *Mary Pappas, et al. v. XTO Energy Inc., et al.*, No. 342−242403−09, filed on December 14, 2009; (ii) *Sanjay Israni, et al. v. XTO Energy Inc., et al.*, No. 017−242424−09, filed on December 15, 2009; (iii) *Michael Walsh, et al. v. XTO Energy Inc., et al.*, No. 153−242432−09, filed on December 15, 2009; (iv) *Ronald Gross, et al. v. XTO Energy Inc., et al.*, No. 141−242460−09, filed on December 16, 2009; (v) *Jeffrey Fink, et al. v. Bob R. Simpson, et al.*, No. 048−242500−09, filed on December 17, 2009; (vi) *Lawrence Treppel, et al. v. XTO Energy Inc., et al.*, No. 342−242523−09, filed on December 18, 2009; (vii) *Nicholas Weil, et al. v. XTO Energy Inc., et al.*, No. 096−242526−09, filed on December 18, 2009; (viii) *Charles Kreps, et al. v. XTO Energy Inc., et al.*, Case No. 352−242548−09, filed on December 21, 2009; (ix) *Murray Silver, et al. v. XTO Energy Inc., et al.*, No. 342−242630−09, filed on December 22, 2009; (x) *William Stratton, et al. v. XTO Energy Inc., et al.*, No. 096−242775−09, filed on December 30, 2009; and (xi) *United Food and Commercial Workers Union Local 880−Retail Food Employers Joint Pension Fund v. XTO Energy Inc., et al.*, No. 342−242849−10, filed on January 6, 2010. On January 12, 2010, the court entered orders consolidating the eleven cases filed as of that date under the caption *In re XTO Energy Shareholder Class Action Litigation*.

Two putative shareholder class actions were filed in the United States District Court for the Northern District of Texas between December 28, 2009 and January 5, 2010. Those cases are styled (i) *James Harrison, et al. v. XTO Energy Inc., et al.*, No. 4:09−cv−768, filed on December 28, 2009 and (ii) *Walt Schumann, et al. v. XTO Energy Inc., et al.*, No. 4:10−cv−007, filed on January 5, 2010. On February 5, 2010, the plaintiffs in the two federal actions filed an unopposed motion to consolidate the cases.

Several putative shareholders filed an individual action in the United States District Court for the Northern District of Texas on February 11, 2010 alleging violations of the federal securities laws based on alleged false and material misrepresentations or omissions in the preliminary proxy filed with the Securities and Exchange Commission in connection with the proposed merger. That case is styled *Mary Pappas, et al. v. Bob R. Simpson, et al.*, No. 4:10−cv−00094−A, filed February 11, 2010.

We believe that all of the putative shareholder lawsuits are without merit and intend to vigorously defend against such claims.

We are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. Our management and legal counsel do not believe that the ultimate resolution of these claims, including the lawsuits described above, will have a material effect on our financial position or liquidity, although an unfavorable outcome could have a material adverse effect on the operations of a given interim period or year.

Other

To date, our expenditures to comply with environmental or safety regulations have not been significant and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Most of our undeveloped acreage is subject to lease expiration if initial wells are not drilled within a specified period, generally not exceeding three years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future.

Table of Contents

7. Financial Instruments

We use commodity−based and financial derivative contracts to manage exposures to commodity price and interest rate fluctuations. We do not hold or issue derivative financial instruments for speculative or trading purposes. We also may enter gas physical delivery contracts to effectively provide gas price hedges. Because these contracts are not expected to be net cash settled, they are considered normal sales contracts. Therefore, these contracts are not recorded in the financial statements.

Commodity Price Hedging Instruments

We periodically enter into futures contracts, energy swaps, collars and basis swaps to hedge our exposure to price fluctuations on natural gas, crude oil and natural gas liquids sales. When actual commodity prices exceed the fixed price provided by these contracts, we pay this excess to the counterparty, and when actual commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. See Note 8.

The fair value of our derivative contracts consists of the following:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31,		December 31,	
(in millions)	2009	2008	2009	2008
Derivatives designated as hedging instruments:				
Natural gas futures and basis swaps	$ 836	$1,917	$ (52)	$ (17)
Crude oil futures and differential swaps	442	1,772	(105)	(12)
Total derivatives designated as hedging instruments	1,278	3,689	(157)	(29)
Derivatives not designated as hedging instruments:				
Natural gas futures and basis swaps	12	9	(8)	(6)
Crude oil futures and differential swaps	—	60	(8)	—
Total derivatives not designated as hedging instruments	12	69	(16)	(6)
Total derivatives	$1,290	$3,758	$(173)	$ (35)

The effects of our cash flow hedges on accumulated other comprehensive income (loss) on the consolidated balance sheets are summarized below.

	Year Ended December 31					
	Change in Hedge Derivative Fair Value			Realized (Gain) Loss Reclassified from OCI into Revenue *(a)*		
(in millions)	2009	2008	2007	2009	2008	2007
Natural gas futures and basis swaps	$1,641	$1,761	$ 255	$(2,955)	$161	$(677)
Crude oil futures and differential swaps	(428)	2,088	(359)	(1,224)	114	(24)
Natural gas liquids futures	—	3	(22)	—	19	—
Total	$1,213	$3,852	$(126)	$(4,179)	$294	$(701)

(a) For realized gains upon contract settlements, the reduction to comprehensive income is offset by contract settlements generally recorded as increases to gas, natural gas liquids or oil revenue. For realized losses upon contract settlements, the increase to other comprehensive income is offset by contract settlements generally recorded as reductions to gas, natural gas liquids or oil revenue.

Table of Contents

The effects of our non−hedge derivatives and the ineffective portion of our hedge derivatives on the consolidated income statements are summarized below.

	Year Ended December 31								
	(Gain) Loss Recognized in Income (Non−Hedge)			(Gain) Loss Recognized in Income (Ineffective Portion)			Derivative Fair Value (Gain) Loss		
(in millions)	2009	2008	2007	2009	2008	2007	2009	2008	2007
Natural gas futures and basis swaps	$ 32	$ (6)	$—	$ (47)	$ 2	$ (22)	$ (15)	$ (4)	$ (22)
Crude oil futures and differential swaps	17	(78)	—	22	(2)	11	39	(80)	11
Natural gas liquids futures	—	—	—	—	(1)	—	—	(1)	—
Total	$ 49	$ (84)	$—	$ (25)	$ (1)	$ (11)	$ 24	$(85)	$ (11)

Derivative Fair Value (Gain) Loss

Derivative fair value (gain) loss comprises the following realized and unrealized components related to non−hedge derivatives and the ineffective portion of hedge derivatives:

(in millions)	2009	2008	2007
Net cash received from counterparties	$(106)	$(13)	$(54)
Non−cash change in derivative fair value	130	(72)	43
Derivative fair value (gain) loss	$ 24	$(85)	$(11)

Fair Value of Financial Instruments

Because of their short−term maturity, the fair value of cash and cash equivalents, accounts receivable and accounts payable approximates their carrying values at December 31, 2009 and 2008. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	December 31, 2009		December 31, 2008	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Net derivative asset	$ 1,117	$ 1,117	$ 3,723	$ 3,723
Total debt	$(10,487)	$(11,526)	$(11,959)	$(11,421)

The fair value of our debt is based upon current market quotes and is the estimated amount required to purchase our debt on the open market. The estimated value does dot include any redemption premium.

Fair Value Measurements

Fair value is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

Assets and liabilities recorded at fair value in the consolidated balance sheets are categorized based upon the level of judgment associated with the inputs used to measure their fair value. Hierarchical levels directly related to the amount of subjectivity associated with the inputs to fair valuation of these assets and liabilities are as follows:

Level I—Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities at the measurement date.

Level II—Inputs (other than quoted prices included in Level I) are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.

Level III—Inputs reflect management's best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

The fair value of our derivative contracts are measured using Level II inputs, and are determined by either market prices on an active market for similar assets or by prices quoted by a broker or other market−corroborated prices. Counterparty credit risk is considered when determining the fair value of our derivative contracts. While our counterparties are generally A− or better rated companies, the fair value of our derivative contracts have been adjusted to account for the risk of nonperformance by the counterparty.

Our asset retirement obligation is measured using primarily Level III inputs. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs, inflation rate and well life. The inputs are calculated based on historical data as well as current estimated costs. See Note 5 for a rollforward of the asset retirement obligation.

The following table summarizes our fair value measurements and the level within the fair value hierarchy in which the fair value measurements fall.

	Fair Value Measurements			
	December 31, 2009		**December 31, 2008**	
(in millions)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Net derivative asset	$ 1,117	$ —	$ 3,723	$ —
Asset retirement obligation	$ —	$ (812)	$ —	$ (759)

Concentrations of Credit Risk

Cash equivalents are high−grade, short−term securities, placed with highly rated financial institutions. Most of our receivables are from a diverse group of companies including major energy companies, pipeline companies, local distribution companies, financial institutions and end−users in various industries. We currently have greater concentrations of credit with several A− or better rated companies. Letters of credit or other appropriate security are obtained as considered necessary to limit risk of loss. Financial and commodity−based swap contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. This exposure is diversified among major investment grade financial institutions, and we have master netting agreements with most counterparties that provide for offsetting payables against receivables from separate derivative contracts. None of our derivative contracts contain credit−risk related contingent features that would require collateralization based on any triggering events. In September 2008, the parent company of one of our counterparties, Lehman Brothers Holdings Inc., filed for bankruptcy, and we recognized a $38 million loss ($24 million after−tax) in derivative fair value (gain) loss in the income statement.

8. Commodity Sales Commitments

Our policy is to consider hedging a portion of our production at commodity prices management deems attractive. While there is a risk we may not be able to realize the benefit of rising prices, management may enter into hedging agreements because of the benefits of predictable, stable cash flows.

In addition to selling gas under fixed−price physical delivery contracts, we enter futures contracts, energy swaps, collars and basis swaps to hedge our exposure to price fluctuations on natural gas, crude oil and natural gas liquids sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We have hedged most of our crude oil sales through December 2010 and a portion of our natural gas sales through December 2011.

Natural Gas

We have entered into natural gas futures contracts and swap agreements that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 7 regarding accounting for commodity hedges.

Production Period		Mcf per Day	Weighted Average NYMEX Price Per Mcf
2010	January to December	1,250,000	$ 7.49
2011	January to December	250,000	$ 7.02

The price we receive for our gas production is generally less than the NYMEX price because of adjustments for delivery location (“basis”), relative quality and other factors. We have entered sell basis swap agreements that effectively fix the basis adjustment as shown below. Not all of our sell basis swap agreements are designated as hedges for hedge accounting purposes. The table below does not include our physical delivery contracts tied to indices at various delivery points.

Production Period		Mcf per Day	Weighted Average Sell Basis per Mcf *(a)*
2010	January to March	632,500	$ 0.43
	April to October	610,000	$ 0.31
	November to December	475,000	$ 0.27
2011	January to October	200,000	$ 0.19
	November to December	170,000	$ 0.17
2012	January to December	50,000	$ 0.27

(a) Reductions to NYMEX gas prices for delivery location.

Net gains on futures and sell basis swap hedge contracts increased gas revenue by $3.0 billion in 2009 and $658 million in 2007. Net losses on these contracts decreased gas revenues by $159 million in 2008. As of December 31, 2009, an unrealized pre−tax derivative fair value gain of approximately $785 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income (loss) (Note 11). Based on December 31 mark−to−market prices, $728 million of this gain is expected to be reclassified into earnings in 2010. The actual reclassification to earnings will be based on mark−to−market prices at the contract settlement date.

Crude Oil

We have entered into crude oil futures contracts and swap agreements that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. Not all of our 2010 crude oil swap agreements are designated as hedges for hedge accounting purposes. See Note 7 regarding accounting for commodity hedges.

Production Period		Bbls per Day	Weighted Average NYMEX Price per Bbl
2010	January to December	70,000	$ 95.70

Net gains on these contracts increased oil revenue by $1.2 billion in 2009 and $24 million in 2007. Net losses on futures and differential swap hedge contracts decreased oil revenue by $114 million in 2008. As of December 31, 2009, an unrealized pre−tax derivative fair value gain of approximately $343 million, related to cash flow hedges of oil price risk, was recorded in accumulated other comprehensive income (loss) (Note 11). Based on December 31 mark−to−market prices, this fair value gain is expected to be reclassified into earnings in 2010. The actual reclassification to earnings will be based on mark−to−market prices at the contract settlement date.

Early Settlement of Hedges

In December 2008 and January 2009, we entered into early settlement and reset arrangements with eight financial counterparties covering a portion of our 2009 natural gas and crude oil hedge volumes. As a result of these early settlements, we received approximately $2.7 billion ($1.7 billion after−tax) which was used to reduce outstanding debt. Of this amount, $453 million ($287 million after−tax) was received in 2008 and the remainder was received in 2009. Under cash flow hedge accounting, the $453 million received in 2008 was included in accumulated other comprehensive income (loss) at December 31, 2008, and was recognized in earnings during 2009 as the hedged production occurred.

Natural Gas Liquids

Net losses on futures contracts decreased natural gas liquids revenue by $19 million in 2008.

Purchase Basis Swaps

We have entered purchase basis swap agreements that effectively fix the basis adjustment as shown below. Some of our purchase basis swap agreements are used to offset our physical delivery basis contracts. This effectively converts the fixed price to a floating price. The remaining purchase basis swap agreements are related to potential purchase of gas volumes to be transported in connection with our commitments under our transportation contracts (Note 6). Purchase basis swap agreements are not designated as hedges for hedge accounting purposes.

Period		Mcf per Day	Weighted Average Purchase Basis per Mcf *(a)*
2010	January to March	103,000	$ 0.24
	April to December	120,000	$ 0.14
2011	January to October	120,000	$ 0.14
	November to December	70,000	$ 0.13
2012	January to December	30,000	$ 0.14
2013	January to May	20,000	$ 0.16

(a) Reductions to NYMEX gas prices for purchase location.

Table of Contents

9. Equity

Stock Splits

We effected a five−for−four stock split on December 13, 2007. All common stock shares, treasury stock shares and per share amounts have been retroactively restated to reflect this stock split.

Common Stock

The following reflects our common stock activity:

	Shares Issued			Shares in Treasury		
(in thousands)	2009	2008	2007	2009	2008	2007
Balance, January 1	585,095	490,434	464,342	5,563	5,140	4,900
Issuance/vesting and forfeiture of performance, restricted and unrestricted shares	2,529	3,778	1,413	783	423	240
Stock option and warrant exercises	1,737	2,741	3,117	—	—	—
Common stock offerings	—	52,900	21,562	—	—	—
Issuance for acquisition of corporations or properties	—	35,242	—	—	—	—
Balance, December 31	589,361	585,095	490,434	6,346	5,563	5,140

In February 2008, we completed a public offering of 23 million common shares at $55.00 per share. After underwriting discount and other offering costs of $42 million, net proceeds of $1.2 billion were used to fund a portion of the $2.3 billion of property acquisitions closed in the first six months of 2008 and to repay indebtedness under our commercial paper program (Note 14).

Our acquisition of properties from Headington Oil Company in July 2008 was partially funded through issuance to the sellers of 11.7 million shares of our common stock (Note 14). We registered these shares under our then outstanding shelf registration statement.

In August 2008, we completed a public offering of 29.9 million common shares at $48.00 per share. After underwriting discount and other offering costs of $48 million, net proceeds of $1.4 billion were used to fund property acquisitions (Note 14) and to pay down outstanding commercial paper borrowings.

Our acquisition of Hunt Petroleum Corporation and other associated entities in September 2008 was partially funded through issuance to the sellers of 23.5 million shares of our common stock (Note 14). We registered these shares under our then outstanding shelf registration statement.

In June 2007, we completed a public offering of 21.6 million common shares at $48.40 per share. After underwriting discount and other offering costs of $35 million, net proceeds of $1.0 billion were used to fund a portion of the acquisition of natural gas and oil properties from Dominion Resources, Inc. (Note 14).

Treasury Stock

In August 2004, our Board of Directors authorized the repurchase of up to 25 million shares of our common stock which may be purchased from time to time in open market or negotiated transactions. As of December 31, 2009, we have repurchased 2.8 million shares.

Shelf Registration Statement

In June 2009, we filed a shelf registration statement with the Securities and Exchange Commission to potentially offer securities which could include debt securities or common stock. The securities will be offered at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities will be used for general corporate purposes, including reduction of bank debt.

Common Stock Warrants

Our purchase of Antero Resources Corporation in 2005 was partially funded by issuance of warrants to purchase 2.6 million shares of common stock at $20.78 per share. The warrants expire on April 1, 2010.

Common Stock Dividends

The Board of Directors declared quarterly dividends of $0.096 per common share for the first three quarters of 2007, $0.12 per common share for fourth quarter 2007 and for each quarter in 2008 and $0.125 for each quarter in 2009. On February 16, 2010, the Board of Directors declared a first quarter 2010 dividend of $0.125 per common share.

The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the Board of Directors and will depend on our financial condition, earnings and cash flow from operations, the level of our capital expenditures, our future business prospects and other matters the Board of Directors deems relevant. In addition, under the terms of the merger agreement with ExxonMobil, during the period before the closing of the merger, we are prohibited from declaring, setting aside or paying any dividend or other distribution except for our regular quarterly cash dividend, which is not to exceed $0.125 per share. The merger agreement also provides that we will coordinate the declaration of dividends with ExxonMobil before the completion of the merger so that both our shareholders and the shareholders of ExxonMobil only receive, in any quarter, one dividend from each company.

See Note 13.

Table of Contents

10. Earnings Per Share

Effective January 1, 2009, we adopted the authoritative guidance for earnings per share as it relates to determining whether instruments granted in share based payment transactions are participating securities. Under the guidance, share−based payment awards that contain nonforfeitable rights to dividends, as is the case with our restricted and performance shares, are participating securities and therefore should be included in computing earnings per share using the two−class method. As a result of adoption, we retrospectively adjusted the calculation of our 2008 and prior periods' earnings per share on a basis consistent with 2009. The following reconciles earnings and shares used in the computation of basic and diluted earnings per common share:

(in millions, except per share data)	Earnings	Shares	Earnings per Share
2009			
Total	$ 2,019	580.2	
Attributable to participating securities	(16)	(4.6)	
Basic	$ 2,003	575.6	$ 3.48
Effect of dilutive securities:			
Stock options	—	2.7	
Warrants	—	1.1	
Diluted	$ 2,003	579.4	$ 3.46
2008			
Total	$ 1,912	534.4	
Attributable to participating securities	(10)	(2.8)	
Basic	$ 1,902	531.6	$ 3.58
Effect of dilutive securities:			
Stock options	—	4.4	
Warrants	—	1.5	
Diluted	$ 1,902	537.5	$ 3.54
2007			
Total	$ 1,691	473.2	
Attributable to participating securities	(4)	(1.3)	
Basic	$ 1,687	471.9	$ 3.57
Effect of dilutive securities:			
Stock options	—	5.9	
Warrants	—	1.4	
Diluted	$ 1,687	479.2	$ 3.52

Certain options to purchase shares of our common stock have been excluded from the 2009 and 2008 diluted calculations because the options are anti−dilutive. Anti−dilutive options for 7.7 million shares in the year ended December 31, 2009 with a weighted average exercise price of $52.18 and 8.0 million shares in the year ended December 31, 2008 period with a weighted average exercise price of $51.01 were excluded.

Table of Contents

11. Accumulated Other Comprehensive Income (Loss)

Our comprehensive income (loss) information is included in the consolidated statements of comprehensive income. The following are components of accumulated other comprehensive income (loss) as of December 31, 2009, 2008 and 2007, and changes during those years:

(in millions)	Fair Value of Derivative Instruments	Post−Retirement Liabilities	Total
Balances, December 31, 2006	$ 488	$ (2)	$ 486
2007 Activity	(827)	(8)	(835)
Deferred taxes	306	3	309
Balances, December 31, 2007	(33)	(7)	(40)
2008 Activity	4,146	(9)	4,137
Deferred taxes	(1,515)	3	(1,512)
Balances, December 31, 2008	2,598	(13)	2,585
2009 Activity	(2,966)	10	(2,956)
Deferred taxes	1,084	(4)	1,080
Balances, December 31, 2009	$ 716	$ (7)	$ 709

12. Supplemental Cash Flow Information

The consolidated statements of cash flows exclude the following non−cash transactions:

- The following restricted share activity (Note 13):
  - Grants of 1.6 million shares in 2009, 2.5 million shares in 2008 and 1.4 million shares in 2007
  - Vesting of 1.7 million shares in 2009, 865,000 shares in 2008 and 427,000 shares in 2007
  - Forfeitures of 83,000 shares in 2009, 51,000 shares in 2008 and 48,000 shares in 2007
- Grants and immediate vesting of unrestricted common shares to nonemployee directors totaling 25,000 shares in each of 2009, 2008 and 2007 (Note 13)
- Grant and immediate vesting of 110,000 unrestricted common shares to our Chairman of the Board and Founder in 2009 (Note 13)
- The following performance share activity (Note 13):
  - Grants of 826,000 shares in 2009 and 1.2 million shares in 2008
  - Vesting of 571,000 shares in 2009, 363,000 shares in 2008 and 166,000 shares in 2007
  - Forfeitures of 15,000 shares in 2007
- Common shares delivered or attested to in satisfaction of the exercise price of employee stock options totaled 700,000 shares at a weighted average price of $46.76 per share in 2009 and 1.5 million shares at a weighted average exercise price of $56.76 per share in 2008.
- Non−cash component of the July 2008 Headington Oil Company acquisition purchase price, including issuance to the sellers of 11.7 million shares of common stock (Note 14)
- Non−cash components of the September 2008 Hunt Petroleum acquisition purchase price, including issuance to the sellers of 23.5 million shares of common stock and assumption of debt and other liabilities (Note 14)

Interest payments totaled $577 million (including $42 million of capitalized interest) in 2009, $499 million (including $39 million of capitalized interest) in 2008 and $231 million (including $30 million of capitalized interest) in 2007. Net income tax payments were $430 million in 2009, $45 million in 2008 and $284 million in 2007.

13. Employee Benefit Plans

401(k) Plan

We sponsor a 401(k) benefit plan that allows employees to contribute and defer a portion of their wages. We match employee contributions up to 14% of wages, subject to annual dollar maximums established by the federal government and plan limitations. Employee contributions vest immediately while our matching contributions vest 100% upon completion of three years of service. All employees over 18 years of age may participate. Company contributions under the plan were $25 million in 2009, $20 million in 2008 and $14 million in 2007.

Stock Incentive Plans

Stock awards under the 2004 Stock Incentive Plan include stock options, performance shares, restricted shares and unrestricted shares. In May 2008, stockholders approved certain amendments and restatements to the 2004 Plan including increasing the shares available for grants of stock awards by 12 million shares, of which 6 million can be granted as full−value awards and authorizing the compensation committee of our board to grant full−value awards to our executive officers. Prior to approval of the 2004 Plan, grants of stock awards were made pursuant to the 1998 Stock Incentive Plan. No further grants will be made under the 1998 Plan. Stock award grants are subject to certain limitations as specified in the Plan. The maximum term of stock awards is ten years under the 1998 Plan and seven years under the 2004 Plan.

The table below summarizes stock incentive compensation expense included in the consolidated financial statements and related amounts for each year:

	Year Ended December 31		
(in millions)	2009	2008	2007
Non−cash stock option compensation expense	$ 43	$ 80	$ 42
Non−cash performance share and unrestricted share compensation expense	26	47	4
Non−cash restricted share compensation expense	68	43	19
Related tax benefit recorded in income statement	50	62	24
Intrinsic value of stock option exercises	68	202	170
Income tax benefit on exercise of stock options or vesting of stock awards *(a)*	20	69	64
Grant date fair value of stock options vested	42	70	35

(a) Recorded as additional paid−in−capital

Stock Options

Stock options granted under the 2004 Plan generally vest and become exercisable ratably over a three−year period, and may include a provision for accelerated vesting when the common stock price reaches specified levels as determined by the Compensation Committee of the Board of Directors. Some stock options granted in 2009, 2008 and 2007 vest only when the common stock price reaches specified levels. There were a total of 18.4 million options outstanding under the 2004 and 1998 Plans at December 31, 2009, including 14.3 million that were exercisable at that date. The table below shows the terms under which the remaining options vest.

(in thousands)	Unvested Stock Options	Vesting
	2,053	Ratably over 3 years
	776	$ 50
	400	$ 54
	2	$ 55
	794	$ 90

The following summarizes option activity and balances for the year ended December 31, 2009:

	Weighted−Average Exercise Price	Stock Options (in thousands)	Weighted−Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Balance at January 1, 2009	$ 36.08	20,290		
Grants	41.94	1,587		
Exercises	26.65	(3,510)		
Forfeitures	43.15	(1)		
Balance at December 31, 2009	$ 38.39	18,366	4.01	$ 203
Exercisable at December 31, 2009	$ 34.52	14,341	3.53	$ 192

As a result of options exercised in 2009, outstanding common stock increased by 1.5 million shares and stockholders' equity increased by $11 million.

Performance Shares

Performance shares granted under the 2004 Plan are subject to restrictions determined by the Compensation Committee of the Board of Directors and are subject to forfeiture if performance criteria are not met. Otherwise, holders of performance shares generally have all the voting, dividend and other rights of other common stockholders. To date, the performance criteria for all awards has been the achievement of specified increases in the common stock price above the market price at the grant date. We granted 826,000 performance shares in 2009 and 1,216,000 performance shares in 2008. There were a total of 1,108,000 performance shares outstanding at December 31, 2009. The table below shows the number of shares and vesting prices of these performance shares.

Performance Shares *(in thousands)*	Vesting Price
390	$ 50
228	$ 55
245	$ 77
245	$ 85

The November 2009 performance share grant totaled 456,000 shares, with half of the shares vesting when the common stock price closes at or above $50 and the other half vesting when the common stock price closes at or above $55. Under the terms of the grant agreement, when the merger agreement with ExxonMobil was signed, the vesting criteria for these shares changed to time vesting, with all of the shares vesting one year after the merger closes. If the merger is not completed, the vesting criteria for the shares would revert to the original price vesting terms.

Restricted Shares

We granted 1,568,000 restricted shares in 2009, 2,537,000 restricted shares in 2008 and 1,388,000 restricted shares in 2007 to key employees other than executive officers. Of the shares granted in 2009, 1,544,000 vest over 42 months, with one−third vesting each at 18, 30 and 42 months. The remaining shares granted in 2009 and previous years vest over three years, with one−third vesting at each grant anniversary date. Holders of restricted shares generally have all the voting, dividend and other rights of other common stockholders.

Unrestricted Share Awards

Nonemployee directors are each eligible to receive discretionary stock awards under the 2004 Plan covering up to 25,000 shares annually, as approved by the Corporate Governance and Nominating Committee and the

Board of Directors. Subsequent to the November 2008 grant, the directors approved a director compensation program whereby nonemployee directors no longer receive stock options and are limited to annual unrestricted grants not to exceed 6,000 shares per director subject to a cap in value of $300,000 as defined in the compensation program.

Nonemployee directors received 4,166 shares each totaling approximately 25,000 unrestricted shares in 2009, 2008 and 2007 under the 2004 Plan. In November 2007, nonemployee directors received 20,000 stock options each totaling 120,000 stock options, 50% of which vested when the common stock price closed above the target price of $56 in 2008 and 50% of which vested when the common stock price closed above the target price of $60 in 2008. In November 2008, nonemployee directors received 20,000 stock options each totaling 120,000 stock options, 50% of which vested when the common stock price closed above the target price of $40 in 2009 and 50% of which vested when the common stock price closed at or above the target price of $45 in 2009.

In January 2009, our Chairman of the Board and Founder received 110,000 unrestricted common shares.

Nonvested Stock Awards

The following summarizes the status of the nonvested stock options, performance shares and restricted shares as of December 31, 2009 and changes for the year then ended:

	Stock Options		Performance Shares		Restricted Shares	
(in thousands, except per share amounts)	**Weighted−Average Grant Date Fair Value**	**Number of Shares**	**Weighted−Average Grant Date Fair Value**	**Number of Shares**	**Weighted−Average Grant Date Fair Value**	**Number of Shares**
Nonvested at January 1, 2009	$ 14.63	5,756	$ 45.37	853	$ 39.87	3,843
Vested	12.70	(3,317)	29.67	(571)	40.53	(1,668)
Grants	11.68	1,587	39.92	826	42.88	1,568
Forfeitures	14.49	(1)	—	—	38.78	(83)
Nonvested at December 31, 2009	$ 15.05	4,025	$ 49.40	1,108	$ 40.88	3,660

As of December 31, 2009, the remaining unrecognized compensation expense related to nonvested stock options was $12 million. Total deferred compensation at December 31, 2009 related to performance shares was $15 million and related to restricted shares was $134 million. For these nonvested stock awards at December 31, 2009, we estimate that stock incentive compensation for service periods after December 31, 2009 will be $90 million in 2010, $45 million in 2011, $18 million in 2012 and $8 million in 2013. The weighted−average remaining vesting period is 1.0 years for stock options, 0.4 years for performance shares, and 2.4 years for restricted shares.

Estimated Fair Value of Grants

We use a trinomial lattice model to value stock option grants that time vest and a Monte Carlo simulation model to value performance shares and stock options that vest, or include a provision for accelerated vesting, when the common stock price reaches specified levels.

During 2009, 2008 and 2007, we used both a trinomial lattice model and a Monte Carlo simulation model to determine the fair value of options granted, and we used a Monte Carlo simulation model to determine the fair value of performance shares granted. For restricted stock grants, the fair value is equal to the closing price of our common stock on the grant date.

The trinomial lattice model requires inputs for risk−free interest rate, dividend yield, volatility, contract term, average vesting period, post−vest turnover rate and suboptimal exercise factor. Both expected life and fair value are outputs of this model. The Monte Carlo simulation model requires inputs for risk−free interest rate, dividend yield, volatility, contract term, target vesting price, post−vest turnover rate and suboptimal exercise factor. The suboptimal exercise factor does not affect the valuation of the performance shares since ownership is transferred at vesting. Expected life, derived vesting period and fair value are outputs of this model.

The risk−free interest rate is based on the constant maturity nominal rates of U.S. Treasury securities with remaining lives throughout the contract term on the day of the grant. The dividend yield is the expected common stock annual dividend yield over the expected life of the option or performance share, expressed as a percentage of the stock price on the date of grant. The volatility factors are based on a combination of both the historical volatilities of our stock and the implied volatility of traded options on our common stock. Contract term is seven years. For options subject to time vesting, the average vesting period is two years, based on each grant vesting ratably over a three−year period. For options subject to vesting when the common stock reaches a specified price, the target vesting price is specified by the award. The post−vesting turnover rate is 1.13% and the suboptimal exercise factor is 1.78, and are both based on actual historical exercise activity. Estimates of fair value are not intended to predict actual future events or the value ultimately realized by certain employees who receive stock option grants, and subsequent events are not indicative of the reasonableness of the original fair value estimates.

We record stock incentive compensation only for awards expected to vest. During 2009, we estimated annual forfeitures using a rate of 0% for stock options, 2% for restricted shares and 0% for performance shares.

During the year ended December 31, 2009, we granted 1.6 million options with an estimated total grant−date fair value of $19 million and a weighted−average fair value of $11.68 per option. During 2008, we granted 2.7 million options with an estimated total grant−date fair value of $47 million and a weighted−average fair value of $17.10 per option. During 2007, we granted 4.3 million options with an estimated total grant−date fair value of $65 million and a weighted−average fair value of $15.29 per option. Fair values were determined using the following assumptions:

	2009	2008	2007
Weighted−average expected term (years)	3.8	4.4	4.6
Range of risk−free interest rates	1.6% − 2.7%	1.7% − 3.5%	3.4% − 5.0%
Weighted−average risk−free interest rates	1.7%	2.7%	3.8%
Dividend yield	1.2%	1.0%	0.8%
Range of volatility	40% − 45%	32% − 53%	26% − 33%
Weighted−average volatility	43%	40%	32%

14. Acquisitions

During the first six months of 2008, we completed acquisitions of both producing and unproved properties for approximately $2.3 billion. These acquisitions included bolt−on acquisitions of additional producing properties, mineral interests and undeveloped leasehold primarily in our Eastern and San Juan Regions and the Barnett, Fayetteville, Woodford and Marcellus Shales. These acquisitions were funded by commercial paper borrowings, proceeds from the February 2008 common stock offering (Note 9) and proceeds from the April 2008 issuance of senior notes (Note 3).

Additionally, in May 2008, we acquired producing properties, leasehold acreage and gathering infrastructure in the Fayetteville Shale from Southwestern Energy Company for approximately $520 million. The purchase price was allocated primarily to unproved properties. The acquisition was funded by proceeds from the April 2008 issuance of senior notes.

In July 2008, we acquired producing properties, leasehold acreage and pipeline and gathering infrastructure in the Marcellus Shale in western Pennsylvania and West Virginia from Linn Energy, LLC for approximately $600 million. The purchase price was allocated primarily to proved and unproved properties. The acquisition was funded in part by proceeds from the April 2008 issuance of senior notes as well as commercial paper borrowings.

In July 2008, we acquired producing and undeveloped acreage located in the Bakken Shale in Montana and North Dakota from Headington Oil Company. The total purchase price was $1.8 billion, and was funded by cash of $1.05 billion and the issuance of 11.7 million shares of common stock to the sellers valued at $742 million (Note 9). The purchase price was allocated primarily to proved properties. The cash portion of the transaction was funded by a combination of operating cash flow and commercial paper.

In September 2008, we acquired Hunt Petroleum Corporation and other associated entities for approximately $4.2 billion, funded by cash of $2.6 billion and the issuance of 23.5 million shares of common stock to the sellers valued at $1.6 billion (Note 9). Hunt Petroleum owned natural gas and oil producing properties primarily concentrated in our Eastern Region, including East Texas and central and north Louisiana. Additional producing properties, both onshore and offshore, are along the Gulf Coast of Texas, Louisiana, Mississippi and Alabama. Non−operating interests, including producing and undeveloped acreage in the North Sea were also conveyed in the transaction. The cash portion of the transaction was funded by a combination of operating cash flow, commercial paper and the August 2008 issuance of senior notes (Note 3).

We believe that the overlap of Hunt Petroleum's assets with ours, primarily in the Eastern Region, as well as the addition of new operating areas in the Gulf Coast and offshore Gulf of Mexico was a significant benefit of the Hunt acquisition. Another important contributing factor of the acquisition was the ability to secure intellectual talent to help exploit these areas as well as others.

Following is the final calculation of the purchase price of Hunt Petroleum Corporation and the allocation to assets and liabilities as of September 2, 2008. The fair value of consideration issued was determined as of June 10, 2008, the date the acquisition was announced.

(in millions)	
Consideration issued to Hunt owners:	
23.5 million shares of common stock (at fair value of $67.95 per share)	$1,597
Cash paid	2,589
Total purchase price	4,186
Fair value of liabilities assumed:	
Current liabilities	385
Long−term debt	337
Asset retirement obligation	168
Other long−term liabilities	5
Deferred income taxes	1,057
Total purchase price plus liabilities assumed	$6,138
Fair value of assets acquired:	
Cash and cash equivalents	$ 198
Other current assets	295
Proved properties	4,065
Unproved properties	250
Other property and equipment	70
Goodwill (non−deductible for income taxes)	1,260
Total fair value of assets acquired	$6,138

In October 2008, we acquired 12,900 acres in the Barnett Shale for approximately $800 million. The acquisition was funded through proceeds from the August 2008 common stock offering (Note 9), our commercial paper program and our revolving credit facility.

On July 31, 2007, we acquired both producing and unproved properties from Dominion Resources, Inc. for $2.5 billion. These properties are located in the Rocky Mountain Region, the San Juan Basin and South Texas.

Table of Contents
The acquisition was funded by the issuance of 21.6 million shares of our common stock in June 2007 for net proceeds of $1.0 billion (Note 9), the issuance of $1.25 billion of senior notes in July 2007 (Note 3) and with borrowings under our commercial paper program, which was repaid with a portion of the proceeds from the issuance of $1.0 billion of senior notes in August 2007 (Note 3). After recording asset retirement obligation of $32 million, other liabilities and transaction costs of $18 million, $2.5 billion was allocated to proved properties and $38 million to unproved properties.

Acquisitions were recorded using the purchase method of accounting. The following presents our unaudited pro forma results of operations for 2008 and 2007 as if the Hunt acquisition was made at the beginning of 2008 and 2007 and the 2007 Dominion acquisition was made at the beginning of 2007. These pro forma results are not necessarily indicative of future results.

	Pro Forma (Unaudited) Year Ended December 31	
(in millions, except per share data)	2008	2007
Revenues	$8,450	$6,648
Net income	$2,090	$1,811
Earnings per common share:		
Basic	$ 3.80	$ 3.58
Diluted	$ 3.76	$ 3.53

15. Quarterly Financial Data *(Unaudited)*

The following are summarized quarterly financial data for the years ended December 31, 2009 and 2008:

	Quarter			
(in millions, except per share data)	1st	2nd	3rd	4th
2009				
Revenues	$2,161	$2,273	$2,288	$2,342
Gross profit *(a)*	$ 978	$ 996	$ 999	$1,070
Net income	$ 486	$ 496	$ 500	$ 537
Earnings per common share: *(b)*				
Basic	$ 0.84	$ 0.86	$ 0.86	$ 0.92
Diluted	$ 0.83	$ 0.85	$ 0.86	$ 0.92
2008				
Revenues	$1,673	$1,936	$2,125	$1,961
Gross profit *(a)*	$ 913	$1,095	$1,052	$ 830
Net income	$ 465	$ 575	$ 521	$ 351*(c)*
Earnings per common share: *(b)*				
Basic	$ 0.93	$ 1.12	$ 0.95	$ 0.61
Diluted	$ 0.92	$ 1.11	$ 0.94	$ 0.61

(a) Operating income before general and administrative expense.
(b) Because quarterly earnings per share is based on the weighted average shares outstanding during the quarter, the sum of quarterly earnings per share may not equal earnings per share for the year. See Note 10 related to our January 1, 2009 adoption of the authoritative guidance regarding calculating earnings per share using the two−class method.
(c) Included in fourth quarter net income is an after−tax impairment of proved properties of $81 million (Note 1).

16. Supplementary Financial Information for Oil and Gas Producing Activities *(Unaudited)*

Substantially all of our operations are directly related to oil and gas producing activities located in the United States. Our international oil and gas producing activities, located in the North Sea, comprise less than 1% of our 2009 and 2008 revenues, costs incurred, reserves and standardized measure.

Costs Incurred Related to Oil and Gas Producing Activities

The following table summarizes costs incurred whether such costs are capitalized or expensed for financial reporting purposes:

(in millions)	2009	2008	2007
Acquisitions:			
Proved properties	$ 30	$ 7,845	$ 3,197
Unproved properties—acquisitions of proved properties *(a)*	—	1,110	260
Unproved properties—other	224	2,094	571
Development *(b)*	2,488	3,355	2,529
Exploration	500	517	257
Asset retirement obligation accrued upon:			
Acquisition	14	202	58
Development *(c)*	26	85	68
Total Costs Incurred	$ 3,282	$ 15,208	$ 6,940

(a) Represents a portion of the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties (Note 14).
(b) Includes capitalized interest of $42 million in 2009, $39 million in 2008 and $30 million in 2007.
(c) Includes revisions of ($7) million in 2009, $52 million in 2008 and $39 million in 2007.

Proved Reserves

Our proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are those quantities of oil and natural gas, 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, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods in which the cost of the required equipment is relatively minor compared with the cost of a new well. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors. Proved reserves exclude volumes deliverable to others under production payments or retained interests.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of 12−month average prices for oil and gas, based on the first−day−of−the−month price for each month in the period, and year end costs for estimated future development and production expenditures to produce year−end estimated proved reserves. Prior to 2009, standardized measure was calculated using year end oil and gas prices and costs.

Prices are not adjusted for the effect of hedge derivatives. Discounted future net cash flows are calculated using a 10% rate. Estimated future income taxes are calculated by applying year−end statutory rates to future pre−tax net cash flows, less the tax basis of related assets and applicable tax credits.

Estimated well abandonment costs, net of salvage values, are deducted from the standardized measure using year−end costs and discounted at the 10% rate. Such abandonment costs are recorded as a liability on the consolidated balance sheet, using estimated values as of the projected abandonment date and discounted using a risk−adjusted rate at the time the well is drilled or acquired (Note 5).

The standardized measure does not represent management’s estimate of our future cash flows or the value of proved oil and gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as effected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

Proved Reserves (in millions)	**Gas (Mcf)**	**Natural Gas Liquids (Bbls)**	**Oil (Bbls)**	**Natural Gas Equivalents (Mcfe)**
December 31, 2006	6,944.2	53.0	214.4	8,548.6
Revisions *(a)*	(46.3)	10.2	15.5	108.2
Extensions, additions and discoveries	1,797.5	5.8	18.4	1,942.5
Production	(532.1)	(4.9)	(17.2)	(664.8)
Purchases in place	1,278.8	2.7	11.3	1,362.7
Sales in place	(1.0)	—	(1.2)	(8.2)
December 31, 2007	9,441.1	66.8	241.2	11,289.0
Revisions *(a)*	(665.5)	(9.4)	(20.9)	(847.3)
Extensions, additions and discoveries	2,195.7	4.2	10.4	2,283.3
Production	(697.4)	(5.7)	(20.5)	(854.7)
Purchases in place	1,529.0	19.9	57.6	1,994.1
Sales in place	—	—	(0.3)	(2.0)
December 31, 2008	11,802.9	75.8	267.5	13,862.4
Revisions *(a)*	(644.4)	18.6	13.2	(453.8)
Extensions, additions and discoveries	2,175.8	6.2	37.9	2,440.8
Production	(855.0)	(7.5)	(24.2)	(1,045.2)
Purchases in place	22.4	0.1	—	23.0
Sales in place	—	—	—	—
December 31, 2009	12,501.7	93.2	294.4	14,827.2

(a) Includes positive price revisions of 165.2 Bcfe in 2007 and negative price revisions of 545.8 Bcfe in 2008 and 620.0 Bcfe in 2009.

The additions to our proved reserves from extensions, additions and discoveries in the last three years are due to the success of our development drilling program. Gas development was concentrated in East Texas and the Barnett, Fayetteville and Woodford shales in 2009. In 2008 and 2007, gas development focused on East Texas and the Barnett Shale. Oil development was concentrated in the Permian Basin and Bakken Shale in 2009 and primarily the Permian Basin in 2008 and 2007. Development and exploration costs totaled $3.0 billion in 2009, $3.9 billion in 2008 and $2.8 billion in 2007. As a result of our 2009 development program, we added approximately 1.8 Tcfe of new undeveloped reserves.

Proved Developed Reserves (in millions)	**Gas (Mcf)**	**Natural Gas Liquids (Bbls)**	**Oil (Bbls)**	**Natural Gas Equivalents (Mcfe)**
December 31, 2006	4,481.6	40.1	167.3	5,725.9
December 31, 2007	6,031.5	52.9	184.8	7,457.7
December 31, 2008	7,290.3	52.5	205.0	8,835.4
December 31, 2009	7,353.1	62.7	212.6	9,004.6

Proved Undeveloped Reserves (in millions)	**Gas (Mcf)**	**Natural Gas Liquids (Bbls)**	**Oil (Bbls)**	**Natural Gas Equivalents (Mcfe)**
December 31, 2006	2,462.6	12.9	47.1	2,822.7
December 31, 2007	3,409.6	13.9	56.4	3,831.3
December 31, 2008	4,512.6	23.3	62.5	5,027.0
December 31, 2009	5,148.6	30.5	81.8	5,822.6

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

	December 31		
(in millions)	**2009**	**2008**	**2007**
Future cash inflows	$ 57,792	$ 65,608	$ 86,080
Future costs:			
Production	(21,114)	(22,239)	(22,066)
Development	(8,484)	(9,159)	(6,065)
Future income tax	(5,525)	(7,902)	(18,423)
Future net cash flows	22,669	26,308	39,526
10% annual discount	(11,808)	(13,515)	(19,988)
Standardized measure	$ 10,861	$ 12,793	$ 19,538

Table of Contents

Changes in Standardized Measure of Discounted Future Net Cash Flows

(in millions)	2009	2008	2007
Standardized measure, January 1	$12,793	$ 19,538	$10,828
Revisions:			
Prices and costs	(1,039)	(14,047)	7,958
Quantity estimates	109	(1,331)	1,868
Accretion of discount	1,279	1,954	970
Future development costs	(797)	(915)	(3,082)
Income tax	1,298	5,259	(3,749)
Production rates and other	(2)	1	—
Net revisions	848	(9,079)	3,965
Extensions, additions and discoveries	2,009	2,714	3,541
Production	(7,250)	(5,879)	(4,359)
Development costs	2,447	2,942	2,299
Purchases in place *(a)*	14	2,560	3,286
Sales in place *(b)*	—	(3)	(22)
Net change	(1,932)	(6,745)	8,710
Standardized measure, December 31	$10,861*(c)*	$ 12,793*(d)*	$19,538*(e)*

(a) Generally based on the year−end present value plus the cash flow received from such properties during the year, rather than the estimated present value at the date of acquisition.
(b) Generally based on beginning of the year present value less the cash flow received from such properties during the year, rather than the estimated present value at the date of sale.
(c) The December 31, 2009 standardized measure includes a reduction of $96 million ($151 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2009 includes a liability of $812 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions.
(d) The December 31, 2008 standardized measure includes a reduction of $93 million ($147 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2008 includes a liability of $759 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions.
(e) The December 31, 2007 standardized measure includes a reduction of $43 million ($68 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2007 includes a liability of $453 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions.

Price and cost revisions are primarily the net result of changes in prices, based on beginning of year reserve estimates. Quantity estimate revisions are primarily the result of the extended economic life of proved reserves and proved undeveloped reserve additions attributable to increased development activity.

Average realized gas prices used in the estimation of proved reserves and calculation of the standardized measure were $3.16 for 2009, $4.66 for 2008, $6.39 for 2007 and $5.46 for 2006. Average realized natural gas liquids prices were $27.18 for 2009, $18.26 for 2008, $60.24 for 2007 and $31.96 for 2006. Average realized oil prices were $55.96 for 2009, $38.12 for 2008, $91.19 for 2007 and $55.47 for 2006. In 2009, we used 12−month average oil and gas prices, based on the first−day−of−the−month price for each month in the period. For periods prior to 2009, we used year end oil and gas prices.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a−15(f) under the Securities Exchange Act of 1934, as amended). Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2009. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework*. Our management has concluded that, based on these criteria, we have maintained in all material respects, effective internal control over financial reporting as of December 31, 2009.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures or our internal controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our Company have been detected.

February 24, 2010

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
XTO Energy Inc.:

We have audited the accompanying consolidated balance sheets of XTO Energy Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of income, stockholders' equity, cash flows, and comprehensive income for each of the years in the three−year period ended December 31, 2009. We also have audited XTO Energy Inc.'s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). XTO Energy Inc. management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures, as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of XTO Energy Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the years in the three−year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, XTO Energy Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

As discussed in Note 10 to the consolidated financial statements, as of January 1, 2009, the Company adopted the authoritative guidance for earnings per share as it relates to determining whether instruments granted in share based payment transactions are participating securities.

KPMG LLP
Fort Worth, Texas
February 24, 2010

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 24th day of February 2010.

XTO ENERGY INC.

By /s/ KEITH A. HUTTON

Keith A. Hutton,
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 24th day of February 2010.

PRINCIPAL EXECUTIVE OFFICERS
(AND DIRECTORS)

/s/ BOB R. SIMPSON
Bob R. Simpson,
Chairman of the Board and Founder

/s/ KEITH A. HUTTON
Keith A. Hutton,
Chief Executive Officer

/s/ VAUGHN O. VENNERBERG II
Vaughn O. Vennerberg II,
President

DIRECTORS

/s/ WILLIAM H. ADAMS III
William H. Adams III

/s/ LANE G. COLLINS
Lane G. Collins

/s/ PHILLIP R. KEVIL
Phillip R. Kevil

/s/ JACK P. RANDALL
Jack P. Randall

/s/ SCOTT G. SHERMAN
Scott G. Sherman

/s/ HERBERT D. SIMONS
Herbert D. Simons

PRINCIPAL FINANCIAL OFFICER

/s/ LOUIS G. BALDWIN
Louis G. Baldwin,
Executive Vice President and Chief Financial Officer

PRINCIPAL ACCOUNTING OFFICER

/s/ BENNIE G. KNIFFEN
Bennie G. Kniffen,
Senior Vice President and Controller

INDEX TO EXHIBITS

Documents filed prior to June 1, 2001 were filed with the Securities and Exchange Commission under our prior name, Cross Timbers Oil Company.

Exhibit No.	Description	Page
2.1+	Agreement and Plan of Merger dated January 9, 2005 among XTO Energy Inc., XTO Barnett Inc., and Antero Resources Corporation (incorporated by reference to Exhibit 2.2 to Form 10−K for the year ended December 31, 2004)	
2.2+	Amendment No. 1 to Agreement and Plan of Merger dated February 3, 2005 among XTO Energy Inc., XTO Barnett Inc., and Antero Resources Corporation (incorporated by reference to Exhibit 2.3 to Form 10−K for the year ended December 31, 2004)	
2.3+	Amendment No. 2 to Agreement and Plan of Merger dated March 22, 2005 among the Company, XTO Barnett Inc., XTO Barnett LLC and Antero Resources Corporation (incorporated by reference to Exhibit 2.1 to Form 8−K filed March 28, 2005)	
2.4+	Amendment No. 3 to Agreement and Plan of Merger dated March 31, 2005 among the Company, XTO Barnett Inc., XTO Barnett LLC and Antero Resources Corporation (incorporated by reference to Exhibit 2.1 to Form 8−K filed April 5, 2005)	
2.5+	Gulf Coast/Rockies/San Juan Package Purchase Agreement dated as of June 1, 2007 between Dominion Exploration & Production, Inc., Dominion Energy, Inc., Dominion Oklahoma Texas Exploration & Production, Inc., Dominion Reserves, Inc., LDNG Texas Holdings, LLC and DEPI Texas Holdings, LLC as Sellers and XTO Energy Inc. as Buyer (incorporated by reference to Exhibit 2.1 to Form 8−K filed August 6, 2007)	
2.6+	Agreement of Sale and Purchase dated May 23, 2008 between Headington Oil Company LLC, et al. and XTO Energy Inc. (incorporated by reference to Exhibit 2.1 to Form 8−K filed July 18, 2008)	
2.7+	Acquisition Agreement dated June 9, 2008 among XTO Energy Inc., HPC Acquisition Corporation, HHEC Acquisition Corporation, Hunt Petroleum Corporation, Hassie Hunt Exploration Company and Hassie Hunt Production Company (incorporated by reference to Exhibit 2.2 to Form 8−K filed July 18, 2008)	
2.8+	Purchase and Sale Agreement dated July 18, 2008 between XTO Energy Inc. and Hollis R. Sullivan Inc., et al. (incorporated by reference to Exhibit 2.1 to Form 8−K filed July 24, 2008)	
2.9+	Agreement and Plan of Merger dated December 13, 2009 among XTO Energy Inc., Exxon Mobil Corporation and ExxonMobil Investment Corporation (incorporated by reference to Exhibit 2.1 to Form 8−K filed December 15, 2009)	
3.1	Restated Certificate of Incorporation of the Company, as restated on June 21, 2006 (incorporated by reference to Exhibit 3.1 to Form 10−Q for the quarter ended June 30, 2006)	
3.2	Amended and Restated Bylaws of the Company as of May 19, 2009 (incorporated by reference to Exhibit 3.1 to Form 8−K filed May 22, 2009)	
4.1	Form of Indenture for Senior Debt Securities dated as of April 23, 2002 between the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.3.1 to Form 8−K filed April 17, 2002)	
4.2	First Supplemental Indenture dated as of April 23, 2002 between the Company and the Bank of New York, as Trustee for the 7 1/2% Senior Notes due 2012 (incorporated by reference to Exhibit 4.2 to Form 10−K for the year ended December 31, 2002)	

Exhibit No.	Description	Page
4.3	Second Supplemental Indenture dated as of October 1, 2005 between the Company and The Bank of New York Trust Company, as Successor Trustee, for 7 1/2% Senior Notes due 2012 (incorporated by reference to Exhibit 4.3 to Form 10−Q for the quarter ended March 31, 2006)	
4.4	Registration Rights Agreement among the Company and partners of Cross Timbers Oil Company, L.P. (incorporated by reference to Exhibit 10.9 to Registration Statement on Form S−1, File No. 33−59820)	
4.5	Indenture dated as of April 23, 2003 between the Company and the Bank of New York, as Trustee for the 6 1/4% Senior Notes due 2013 (incorporated by reference to Exhibit 4.1 to Form 10−Q for the quarter ended March 31, 2003)	
4.6	First Supplemental Indenture dated as of October 1, 2005 between the Company and The Bank of New York Trust Company, as Successor Trustee, for 6 1/4% Senior Notes due 2013 (incorporated by reference to Exhibit 4.4 to Form 10−Q for the quarter ended March 31, 2006)	
4.7	Indenture for Senior Debt Securities dated as of January 22, 2004 between the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.3.1 to Form 8−K filed January 16, 2004)	
4.8	First Supplemental Indenture dated as of January 22, 2004 between the Company and the Bank of New York, as Trustee for the 4.90% Senior Notes due 2014 (incorporated by reference to Exhibit 4.3.2 to Form 8−K filed January 16, 2004)	
4.9	Second Supplemental Indenture dated as of October 1, 2005 between the Company and The Bank of New York Trust Company, as Successor Trustee, for 4.90% Senior Notes due 2014 (incorporated by reference to Exhibit 4.5 to Form 10−Q for the quarter ended March 31, 2006)	
4.10	Indenture dated as of September 23, 2004 between the Company and the Bank of New York, as Trustee for the 5% Senior Notes due 2015 (incorporated by reference to Exhibit 4.1 to Form 8−K filed September 24, 2004)	
4.11	First Supplemental Indenture dated as of October 1, 2005 between the Company and The Bank of New York Trust Company, as Successor Trustee, for 5% Senior Notes due 2015 (incorporated by reference to Exhibit 4.6 to Form 10−Q for the quarter ended March 31, 2006)	
4.12	Indenture for Senior Debt Securities dated as of April 13, 2005 between the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.3.1 to Form 8−K filed April 12, 2005)	
4.13	First Supplemental Indenture dated as of April 13, 2005 between the Company and the Bank of New York, as Trustee for 5.30% Senior Notes due 2015 (incorporated by reference to Exhibit 4.3.2 to Form 8−K filed April 12, 2005)	
4.14	Second Supplemental Indenture dated as of October 1, 2005 between the Company and The Bank of New York Trust Company, as Successor Trustee, for 5.30% Senior Notes due 2015 (incorporated by reference to Exhibit 4.1 to Form 10−Q for the quarter ended March 31, 2006)	
4.15	Third Supplemental Indenture dated as of March 30, 2006 between the Company and The Bank of New York Trust Company, as Trustee, for 5.65% Senior Notes due 2016 and 6.10% Senior Notes due 2036 (incorporated by reference to Exhibit 4.2 to Form 10−Q for the quarter ended March 31, 2006)	

Exhibit No.	Description	Page
4.16	Registration Rights Agreement dated April 1, 2005 among the Company and the security holders of Antero Resources Corporation (incorporated by reference to Exhibit 4.1 to Form 10−Q for the quarter ended June 30, 2005)	
4.17	Indenture for Senior Debt Securities dated as of July 19, 2007 between the Company and the Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.3.1 to Form 8−K filed July 16, 2007)	
4.18	First Supplemental Indenture dated as of July 19, 2007 between the Company and the Bank of New York Trust Company, N.A., as Trustee for 5.90% Senior Notes due 2012, 6.25% Senior Notes due 2017 and 6.75% Senior Notes due 2037 (incorporated by reference to Exhibit 4.3.2 to Form 8−K filed July 16, 2007)	
4.19	Second Supplemental Indenture dated as of April 18, 2008 between the Company and the Bank of New York Trust Company, N.A., as Trustee for 4.625% Senior Notes due 2013, 5.50% Senior Notes due 2018 and 6.375% Senior Notes due 2038 (incorporated by reference to Exhibit 4.3.3 to Form 8−K filed April 16, 2008)	
4.20	Third Supplemental Indenture dated as of August 7, 2008 between the Company and the Bank of New York Trust Company, N.A., as Trustee for 5% Senior Notes due 2010, 5.75% Senior Notes due 2013 and 6.50% Senior Notes due 2018 (incorporated by reference to Exhibit 4.3.4 to Form 8−K filed August 5, 2008)	
10.1*	Employment Agreement between the Company and Bob R. Simpson, dated May 16, 2006 (incorporated by reference to Exhibit 10.2 to Form 10−Q for the quarter ended June 30, 2006)	
10.2*	Amendment to Employment Agreement between the Company and Bob R. Simpson, dated December 31, 2007 (incorporated by reference to Exhibit 10.1 to Form 8−K filed January 7, 2008)	
10.3*	Employment Agreement between the Company and Bob R. Simpson, dated November 18, 2008 (incorporated by reference to Exhibit 10.3 to Form 10−K for the year ended December 31, 2008)	
10.4*	Amendment to Employment Agreement between the Company and Bob R. Simpson, dated September 16, 2009 (incorporated by reference to Exhibit 10.1 to Form 10−Q for the quarter ended September 30, 2009)	
10.5*	Amendment No. 2 to Employment Agreement between the Company and Bob R. Simpson, dated December 13, 2009	
10.6*	Employment Agreement between the Company and Keith A. Hutton, dated May 16, 2006 (incorporated by reference to Exhibit 10.3 to Form 10−Q for the quarter ended June 30, 2006)	
10.7*	Employment Agreement between the Company and Keith A. Hutton, dated November 18, 2008 (incorporated by reference to Exhibit 10.5 to Form 10−K for the year ended December 31, 2008)	
10.8*	Amendment to Employment Agreement between the Company and Keith A. Hutton, dated December 13, 2009	
10.9*	Employment Agreement between the Company and Vaughn O. Vennerberg II, dated May 16, 2006 (incorporated by reference to Exhibit 10.4 to Form 10−Q for the quarter ended June 30, 2006)	

Table of Contents

Exhibit No.	Description	Page
10.10*	Employment Agreement between the Company and Vaughn O. Vennerberg II, dated November 18, 2008 (incorporated by reference to Exhibit 10.7 to Form 10−K for the year ended December 31, 2008)	
10.11*	Amendment to Employment Agreement between the Company and Vaughn O. Vennerberg II, dated December 13, 2009	
10.12*	1998 Stock Incentive Plan, as amended March 17, 2004 (incorporated by reference to Exhibit 10.1 to Form 10−Q for the quarter ended March 31, 2004)	
10.13*	Consulting Agreement among XTO Energy Inc., Exxon Mobil Corporation and Bob R. Simpson, dated December 13, 2009 (incorporated by reference to Exhibit 99.1 to Form 8−K filed December 15, 2009) **	
10.14*	Consulting Agreement among XTO Energy Inc., Exxon Mobil Corporation and Keith A. Hutton, dated December 13, 2009 (incorporated by reference to Exhibit 99.2 to Form 8−K filed December 15, 2009) **	
10.15*	Consulting Agreement among XTO Energy Inc., Exxon Mobil Corporation and Vaughn O. Vennerberg II, dated December 13, 2009 (incorporated by reference to Exhibit 99.3 to Form 8−K filed December 15, 2009) **	
10.16*	Consulting Agreement among XTO Energy Inc., Exxon Mobil Corporation and Louis G. Baldwin, dated December 13, 2009 (incorporated by reference to Exhibit 99.4 to Form 8−K filed December 15, 2009) **	
10.17*	Consulting Agreement among XTO Energy Inc., Exxon Mobil Corporation and Timothy L. Petrus, dated December 13, 2009 (incorporated by reference to Exhibit 99.5 to Form 8−K filed December 15, 2009) **	
10.18*	XTO Energy Inc. Amended and Restated 2004 Stock Incentive Plan (incorporated by reference to Appendix B to the Proxy Statement dated April 13, 2006 for the Annual Meeting of Stockholders held May 16, 2006)	
10.19*	XTO Energy Inc. Amended and Restated 2004 Stock Incentive Plan (as amended and restated through November 21, 2006) (incorporated by reference to Exhibit 10.10 to Form 10−K for the year ended December 31, 2006)	
10.20*	XTO Energy Inc. 2004 Stock Incentive Plan, as Amended and Restated as of May 20, 2008 (incorporated by reference to Appendix B to the Proxy Statement dated April 21, 2008 for the Annual Meeting of Stockholders held May 20, 2008)	
10.21*	Form of Nonqualified Stock Option Agreement for Employees under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8−K filed November 22, 2004)	
10.22*	Form of Nonqualified Stock Option Agreement for Employees with Employment Agreements under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 10−Q for the quarter ended September 30, 2006)	
10.23*	Form of Stock Award Agreement for Employees under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8−K filed November 22, 2004)	
10.24*	Second Form of Stock Award Agreement for Employees under the 2004 Stock Incentive Plan	

Table of Contents

Exhibit No.	Description	Page
10.25*	Form of Nonqualified Stock Option Agreement for Non−Employee Directors under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8−K filed November 22, 2004)	
10.26*	Form of Stock Award Agreement for Non−Employee Directors under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8−K filed November 22, 2004)	
10.27*	Form of Stock Grant Agreement for Non−Employee Directors under Section 11 of the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8−K filed February 22, 2005)	
10.28*	Form of Stock Grant Agreement (With Restrictions) for Non−Employee Directors under Section 11 of the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.18 to Form 10−K for the year ended December 31, 2007)	
10.29*	Form of Stock Award Agreement (Restricted Shares) for Employees under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.30 to Form 10−K for the year ended December 31, 2006)	
10.30*	Second Form of Stock Award Agreement (Restricted Shares) for Employees under the 2004 Stock Incentive Plan	
10.31*	Form of Stock Award Agreement for Employees with Employment Agreements under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 10−Q for the quarter ended June 30, 2008)	
10.32*	Form of Stock Grant Agreement to Chairman under Section 11 of the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.21 to Form 10−K for the year ended December 31, 2008)	
10.33*	Second Form of Stock Award Agreement for Employees with Employment Agreements under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.22 to Form 10−K for the year ended December 31, 2008)	
10.34*	Second Form of Nonqualified Stock Option Agreement for Employees with Employment Agreements under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.23 to Form 10−K for the year ended December 31, 2008)	
10.35*	Second Amended and Restated Management Group Employee Severance Protection Plan, as amended August 15, 2006 (incorporated by reference to Exhibit 10.2 to Form 10−Q for the quarter ended September 30, 2006)	
10.36*	Third Amended and Restated Management Group Employee Severance Protection Plan, as amended November 18, 2008 (incorporated by reference to Exhibit 10.25 to Form 10−K for the year ended December 31, 2008)	
10.37*	Fourth Amended and Restated Management Group Employee Severance Protection Plan, as amended December 13, 2009 **	
10.38*	Amended and Restated Outside Directors Severance Plan, as amended August 15, 2006 (incorporated by reference to Exhibit 10.3 to Form 10−Q for the quarter ended September 30, 2006)	
10.39*	Amended and Restated Outside Directors Severance Plan, as amended November 18, 2008 (incorporated by reference to Exhibit 10.27 to Form 10−K for the year ended December 31, 2008)	

Table of Contents

Exhibit No.	Description	Page
10.40*	Form of Amended and Restated Agreement (relating to change in control) between the Company and Bob R. Simpson, Keith A. Hutton, Vaughn O. Vennerberg II and Louis G. Baldwin, dated October 15, 2004 (incorporated by reference to Exhibit 10.1 to Form 8−K filed October 21, 2004)	
10.41*	Form of Amendment No. One to Amended and Restated Agreement (relating to change in control) between the Company and Bob R. Simpson, Keith A. Hutton, Vaughn O. Vennerberg II and Louis G. Baldwin, dated November 21, 2006 (incorporated by reference to Exhibit 10.26 to Form 10−K for the year ended December 31, 2006)	
10.42*	Amendment Number Two to Amended and Restated Agreement (relating to change in control) between the Company and Bob R. Simpson, dated December 31, 2007 (incorporated by reference to Exhibit 10.2 to Form 8−K filed January 7, 2008)	
10.43*	Agreement (relating to change in control) between the Company and Timothy L Petrus, dated November 21, 2006 (incorporated by reference to Exhibit 10.27 to Form 10−K for the year ended December 31, 2006)	
10.44*	Amended and Restated Agreement (relating to change in control) between the Company and Bob R. Simpson, dated November 18, 2008 (incorporated by reference to Exhibit 10.32 to Form 10−K for the year ended December 31, 2008)	
10.45*	Form of Amended and Restated Agreement (relating to change in control) between the Company and Keith A. Hutton, Vaughn O. Vennerberg II, Louis G. Baldwin and Timothy L. Petrus, dated November 18, 2008 (incorporated by reference to Exhibit 10.33 to Form 10−K for the year ended December 31, 2008)	
10.46*	Amendment to Amended and Restated Agreement (relating to change in control) between the Company and Bob R. Simpson, dated December 13, 2009 (incorporated by reference to Exhibit 99.6 to Form 8−K filed December 15, 2009)	
10.47*	Amendment to Amended and Restated Agreement (relating to change in control) between the Company and Keith A. Hutton, dated December 13, 2009 (incorporated by reference to Exhibit 99.7 to Form 8−K filed December 15, 2009)	
10.48*	Amendment to Amended and Restated Agreement (relating to change in control) between the Company and Vaughn O. Vennerberg II, dated December 13, 2009 (incorporated by reference to Exhibit 99.8 to Form 8−K filed December 15, 2009)	
10.49*	Amendment to Amended and Restated Agreement (relating to change in control) between the Company and Louis G. Baldwin, dated December 13, 2009 (incorporated by reference to Exhibit 99.9 to Form 8−K filed December 15, 2009)	
10.50*	Amendment to Amended and Restated Agreement (relating to change in control) between the Company and Timothy L. Petrus, dated December 13, 2009 (incorporated by reference to Exhibit 99.10 to Form 8−K filed December 15, 2009)	
10.51*	XTO Energy Inc. 2009 Executive Incentive Compensation Plan (incorporated by reference to Appendix C to the Proxy Statement dated April 17, 2009 for the Annual Meeting of Stockholders held May 19, 2009)	
10.52*	Form of Indemnification Agreement dated November 15, 2005 between the Company and each director, executive officer and certain other officers (incorporated by reference to Exhibit 10.1 to Form 8−K filed November 18, 2005)	

Table of Contents

Exhibit No.	Description	Page
10.53*	Description of Matching Charitable Contribution Program for officers and directors (incorporated by reference to Exhibit 10.34 to Form 10−K for the year ended December 31, 2007)	
10.54	Amended and Restated 5−Year Revolving Credit Agreement dated April 1, 2005 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.3 to Form 10−Q for the quarter ended March 31, 2005)	
10.55	First Amendment to Five−Year Revolving Credit Agreement dated March 10, 2006 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.1 to Form 10−Q for the quarter ended March 31, 2006)	
10.56	Second Amendment to Five−Year Revolving Credit Agreement dated October 25, 2006 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.5 to Form 10−Q for the quarter ended September 30, 2006)	
10.57	Third Amendment to 5−Year Revolving Credit Agreement dated March 19, 2007 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.1 to Form 8−K filed March 23, 2007)	
10.58	Fourth Amendment to 5−Year Revolving Credit Agreement dated February 6, 2008 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.39 to Form 10−K for the year ended December 31, 2007)	
10.59	Commitment Increase and Accession Agreement dated July 17, 2008 between XTO Energy Inc. and certain banks named therein (incorporated by reference to Exhibit 10.3 to Form 10−Q for the quarter ended June 30, 2008)	
10.60	Term Loan Credit Agreement dated November 10, 2004 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.20 to Form S−4 dated December 13, 2004)	
10.61	First Amendment to Term Loan Agreement dated April 1, 2005 between the Company and certain banks named therein (incorporated by reference to Exhibit 10.4 to Form 10−Q for the quarter ended March 31, 2005)	
10.62	Second Amendment to Term Loan Agreement dated March 10, 2006 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.2 to Form 10−Q for the quarter ended March 31, 2006)	
10.63	Third Amendment to Term Loan Agreement dated March 19, 2007 between the Company and certain banks named therein (incorporated by reference to Exhibit 10.2 to Form 8−K filed March 23, 2007)	
10.64	Fourth Amendment to Term Loan Agreement dated February 6, 2008 between the Company and certain banks named therein (incorporated by reference to Exhibit 10.44 to Form 10−K for the year ended December 31, 2007)	
10.65	Form of Commercial Paper Dealer Agreement dated October 27, 2006 between the Company and each of Lehman Brothers Inc., Citigroup Global Markets Inc., Goldman, Sachs & Co. and JP Morgan Securities Inc. (incorporated by reference to Exhibit 10.1 to Form 8−K filed November 2, 2006)	
10.66	Issuing and Paying Agency Agreement dated October 27, 2006 between the Company and JP Morgan Chase Bank, National Association (incorporated by reference to Exhibit 10.2 to Form 8−K filed November 2, 2006)	

Exhibit No.	Description	Page
10.67	Firm Intrastate Gas Transportation Agreement dated July 1, 2005 between the Company, XTO Resources I, LP and Energy Transfer Fuel, LP (incorporated by reference to Exhibit 10.1 to Form 10−Q for the quarter ended September 30, 2005) (Material has been omitted from this Exhibit pursuant to an order of confidential treatment and the omitted material has been separately filed with the Securities and Exchange Commission.)	
12.1	Computation of Ratio of Earnings to Fixed Charges	
21.1	Subsidiaries of XTO Energy Inc.	
23.1	Consent of KPMG LLP	
23.2	Consent of Miller and Lents, Ltd.	
31.1	Chief Executive Officer Certification required by Rule 13a−14(a)/15d−14(a) of the Securities Exchange Act of 1934	
31.2	Chief Financial Officer Certification required by Rule 13a−14(a)/15d−14(a) of the Securities Exchange Act of 1934	
32.1	Chief Executive Officer and Chief Financial Officer Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes−Oxley Act of 2002	
99.1	Miller and Lents, Ltd. Report	
101	The following financial statements from XTO Energy Inc.'s Annual Report on Form 10−K for the year ended December 31, 2009, filed on February 25, 2010, formatted in XBRL; (i) Consolidated Balance Sheets, (ii) Consolidated Income Statements, (iii) Consolidated Statements of Comprehensive Income, (iv) Consolidated Statements of Cash Flows, (v) Consolidated Statements of Stockholders' Equity and (vi) the Notes to Consolidated Financial Statements, tagged as blocks of text.	

+ All schedules and similar attachments have been omitted. The Company agrees to furnish supplementally a copy of the omitted schedules and similar attachments to the Securities and Exchange Commission upon request.
* Management contract or compensatory plan
** To be effective upon completion of the merger with Exxon Mobil Corporation.

Copies of the above exhibits not contained herein are available, at the cost of reproduction, to any security holder upon written request to the Secretary, XTO Energy Inc., 810 Houston Street, Fort Worth, Texas 76102.

EXHIBIT 10.5

AMENDMENT NO. 2 TO
EMPLOYMENT AGREEMENT

WHEREAS, XTO Energy, Inc., a Delaware Corporation (the "Company") and Bob R. Simpson ("Employee") entered into an Employment Agreement, dated as of November 18, 2008, effective as of December 1, 2008, and subsequently amended on September 16, 2009 (the "Agreement"); and

WHEREAS, pursuant to Section 18 of the Agreement, the Agreement may be amended by mutual written agreement signed by the Company and Employee (the "Parties"); and

WHEREAS, the Parties desire to amend certain provisions in the Agreement as hereinafter set forth in this Amendment No. 2 to the Agreement (this "Amendment").

NOW, THEREFORE, for and in consideration of the mutual promises, covenants and obligations contained herein, the Parties agree as follows:

1. The second sentence of each of Section 11.1(a) and Section 11.1(g) is hereby amended by replacing the phrase "forty−five (45) days" with the phrase "five (5) days."

2. The first sentence of Section 13.2 is hereby amended by replacing the phrase "an independent accounting firm retained by Employer on the date of the Change in Control" with the phrase "the accounting firm acting as Employer's independent auditor immediately prior to the Change in Control."

3. This Amendment shall be governed by and construed under the laws of the State of Texas.

4. This Amendment may be executed in one or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

5. Except as amended hereby, the Agreement shall remain in full effect.

IN WITNESS WHEREOF, the Parties have caused this Amendment No. 2 to the Employment Agreement to be executed and delivered on December 13, 2009, to be effective immediately.

XTO ENERGY INC.

By: /s/ Vaughn O. Vennerberg, II
Name: Vaughn O. Vennerberg, II
Title: President

EMPLOYEE

/s/ Bob R. Simpson
Bob R. Simpson

EXHIBIT 10.8

AMENDMENT TO
EMPLOYMENT AGREEMENT

WHEREAS, XTO Energy Inc., a Delaware Corporation (the "Company") and Keith A. Hutton ("Employee") entered into an Employment Agreement, dated as of November 18, 2008, effective as of December 1, 2008 (the "Agreement");

WHEREAS, pursuant to Section 18 of the Agreement, the Agreement may be amended by mutual written agreement signed by the Company and Employee (the "Parties"); and

WHEREAS, the Parties desire to amend certain provisions in the Agreement as hereinafter set forth in this Amendment to the Agreement (this "Amendment").

NOW, THEREFORE, for and in consideration of the mutual promises, covenants and obligations contained herein, the Parties agree as follows:

1. The second and last sentences of Section 6.1 are hereby deleted in their entirety.

2. The first sentence of Section 13.2 is hereby amended by replacing the phrase "an independent accounting firm retained by Employer on the date of determination" with the phrase "the accounting firm acting as Employer's independent auditor immediately prior to the Change in Control."

3. This Amendment shall be governed by and construed under the laws of the State of Texas.

4. This Amendment may be executed in one or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

5. Except as amended hereby, the Agreement shall remain in full effect.

IN WITNESS WHEREOF, the Parties have caused this Amendment to the Employment Agreement to be executed and delivered on December 13, 2009, to be effective immediately.

XTO ENERGY INC.

By: /s/ Vaughn O. Vennerberg, II
Name: Vaughn O. Vennerberg, II
Title: President

EMPLOYEE

/s/ Keith A. Hutton
Keith A. Hutton

EXHIBIT 10.11

AMENDMENT TO
EMPLOYMENT AGREEMENT

WHEREAS, XTO Energy Inc., a Delaware Corporation (the "Company") and Vaughn O. Vennerberg, II ("Employee") entered into an Employment Agreement, dated as of November 18, 2008, effective as of December 1, 2008 (the "Agreement");

WHEREAS, pursuant to Section 18 of the Agreement, the Agreement may be amended by mutual written agreement signed by the Company and Employee (the "Parties"); and

WHEREAS, the Parties desire to amend certain provisions in the Agreement as hereinafter set forth in this Amendment to the Agreement (this "Amendment").

NOW, THEREFORE, for and in consideration of the mutual promises, covenants and obligations contained herein, the Parties agree as follows:

1. The second and last sentences of Section 6.1 are hereby deleted in their entirety.

2. The first sentence of Section 13.2 is hereby amended by replacing the phrase "an independent accounting firm retained by Employer on the date of determination" with the phrase "the accounting firm acting as Employer's independent auditor immediately prior to the Change in Control."

3. This Amendment shall be governed by and construed under the laws of the State of Texas.

4. This Amendment may be executed in one or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

5. Except as amended hereby, the Agreement shall remain in full effect.

IN WITNESS WHEREOF, the Parties have caused this Amendment to the Employment Agreement to be executed and delivered on December 13, 2009, to be effective immediately.

XTO ENERGY INC.

By: /s/ Karen S. Wilson
Name: Karen S. Wilson
Title: Vice President – Human Resources

EMPLOYEE

/s Vaughn O. Vennerberg, II
Vaughn O. Vennerberg, II

Exhibit 10.24

FORM OF STOCK AWARD AGREEMENT FOR EMPLOYEES UNDER THE XTO ENERGY INC. 2004 STOCK INCENTIVE PLAN, AS AMENDED AND RESTATED AS OF MAY 20, 2008

THIS AGREEMENT is entered into this 17th day of November, 2009, between XTO Energy Inc., a Delaware corporation (the "Company"), and (“Grantee”), pursuant to the provisions of the XTO Energy Inc. 2004 Stock Incentive Plan, as Amended and Restated as of May 20, 2008 (the "Plan"). The Compensation Committee of the Board of Directors of the Company (the "Committee") has determined that Grantee is eligible to be a participant in the Plan and, to carry out its purposes, has this day authorized the grant, pursuant to the Plan, of the stock award set forth below to Grantee.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the parties do hereby agree as follows:

1. **Grant of Stock Award**. Subject to all of the terms, conditions and provisions of the Plan and of this Agreement, the Company hereby grants to Grantee under Section 10 of the Plan shares of the common stock of the Company, par value one cent ($0.01) per share (the "Common Stock"), which shares will consist of authorized but unissued shares or issued shares reacquired by the Company. Such shares are being issued as a stock award in the form of performance shares under the Plan.

2. **Vesting**. Fifty percent (50%) of the performance shares granted herein will vest when the Common Stock closes on the New York Stock Exchange at or above each of the following levels: $50.00 and $55.00 per share; provided, however, that if prior to the performance shares granted herein vesting as a result of the Common Stock's closing at or above one or both price levels, the Company announces that it has entered into a definitive agreement with respect to any transaction that could result in a Change in Control (as defined in the Plan) in which the Company is not the surviving public company, the unvested performances shares shall not, except as provided below, vest as a result of any closing prices of the Common Stock on any trading day from and after such announcement. In the event of any such Change in Control, the unvested performance shares shall vest on the earlier of the first anniversary of the closing of the transaction resulting in the Change in Control or on the first trading day on which the Common Stock closes at or above the applicable price levels after two full trading days following the announcement that the definitive agreement relating to the Change in Control transaction has been terminated. If the Common Stock is not listed on the New York Stock Exchange, then any reference in this Agreement to the New York Stock Exchange will be deemed to be the principal securities market on which the Common Stock is traded or quoted.

3. **Grantee's Agreement**. Grantee expressly and specifically agrees that:

(a) With respect to the calendar year in which any of the performance shares vest, Grantee will include in his or her gross income for federal, state and local income tax purposes the fair market value of the performance shares that vested.

(b) The grant of performance shares is special incentive compensation that will not be taken into account as "wages" or "salary" in determining the amount of payment or benefit to Grantee under any other compensation or insurance plan of the Company, including without limitation the Third Amended and Restated XTO Energy Inc. Management Group Employee Severance Protection Plan (as the same may be amended from time to time or any successor thereto, the "Management Plan") and the Third Amended and Restated XTO Energy Inc. Employee Severance Protection Plan (as the same may be amended from time to time or any successor thereto, the "Employee Plan").

(c) The Company may hold the certificate for unvested performance shares until the performance shares vest or the performance shares may be uncertificated shares issued in the name of the Grantee and held in a restricted account by the Company's transfer agent. As contemplated and permitted by the provisions of Section 4.04 of the Management Plan and Section 4.02 of the Employee Plan as such plans are currently in effect, the unvested performance shares granted herein (including the price levels at which vesting may occur), and all other Awards (as defined in the Plan) previously granted by the Company to Grantee under the Plan, are subject to adjustment as and to the extent provided in Sections 5(f) and 19 of the Plan in the sole discretion of the Committee, subject only to the restrictions on the Committee's discretion specifically set forth in this Agreement and prior Award agreements.

(d) Grantee may pay to the Company any federal, state or local tax withholding owed as a result of the performance shares vesting with shares of Common Stock owned by Grantee on the date of vesting or with the shares of unrestricted Common Stock acquired upon vesting (the shares of Common Stock being valued at fair market value on the date of vesting).

4. **Term**. Any performance shares which remain unvested on the seventh anniversary of the date of this Agreement will be canceled, will not vest, and will be returned to the Company.

5. **Death or Disability**. Upon death of Grantee, or upon termination of Grantee's employment by reason of permanent disability (as determined by the Committee), all unvested performance shares granted herein will immediately vest.

6. **Other Terms, Conditions and Provisions**. As noted above, just as with all other Awards granted to Grantee under the Plan, the performance shares herein granted by the Company to Grantee are granted subject to all of the terms, conditions and provisions of the Plan, including without limitation the Committee discretion reserved in the adjustment provisions of Sections 5(f) and 19 of the Plan. Grantee

hereby acknowledges receipt of a copy of the Plan and Plan prospectus and hereby consents to receive any updates to the Plan or Plan prospectus electronically. The parties agree that the entire text of the Plan is incorporated by reference as if copied herein. Reference is made to the Plan for a full description of the rights of Grantee and the limitations thereon set forth in the terms, conditions and provisions of the Plan applicable to the performance shares granted herein. If any of the provisions of this Agreement or of the Management Plan, the Employee Plan or any other compensation or insurance plan of the Company vary from or are in conflict with the Plan, the provisions of the Plan will be controlling.

7. **Non−Transferability**. The performance shares granted herein are not transferable or assignable by Grantee.

8. **Rights as a Stockholder**. Grantee will have the voting, dividend, and other rights of stockholders of the Company prior to and upon vesting of the performance shares. If the performance shares are canceled, all such rights will then be canceled.

9. **No Employment Commitment**. Grantee acknowledges that neither the grant of performance shares nor the execution of this Agreement by the Company will be interpreted or construed as imposing upon the Company any obligation to retain Grantee’s services for any stated period of time, which employment will continue to be at the pleasure of the Company at such compensation as it determines, unless otherwise provided in a written employment agreement signed by the Company and Grantee.

IN WITNESS WHEREOF, this Agreement is executed and entered into effective on the day and year first above expressed.

XTO ENERGY INC.

By: ______________________________
Name: Bob R. Simpson
Title: Chairman of the Board and Founder

GRANTEE

____

Exhibit 10.30

**FORM OF STOCK AWARD
AGREEMENT (RESTRICTED SHARES) FOR EMPLOYEES UNDER THE
XTO ENERGY INC. 2004 STOCK INCENTIVE PLAN,
AS AMENDED AND RESTATED AS OF MAY 20, 2008**

THIS AGREEMENT is entered into this day of , 200 , between XTO Energy Inc., a Delaware corporation (the "Company"), and ("Grantee"), pursuant to the provisions of the XTO Energy Inc. 2004 Stock Incentive Plan, as Amended and Restated as of May 20, 2008 (the "Plan"). The Compensation Committee of the Board of Directors of the Company (the "Committee") has determined that Grantee is eligible to be a participant in the Plan and, to carry out its purposes, has this day authorized the grant, pursuant to the Plan, of the stock award set forth below to Grantee.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the parties do hereby agree as follows:

1. **Grant of Stock Award**. Subject to all of the terms, conditions and provisions of the Plan and of this Agreement, the Company hereby grants to Grantee under Section 10 of the Plan shares of the common stock of the Company, par value one cent ($0.01) per share (the "Common Stock"), which shares will consist of authorized but unissued shares or issued shares reacquired by the Company. Such shares are being issued as a stock award in the form of restricted shares under the Plan.

2. **Vesting**. The restricted shares granted herein will vest in one−third increments on each of the 18 month, 30 month and 42 month anniversaries of the Grant Date.

3. **Grantee's Agreement**. Grantee expressly and specifically agrees that:

(a) With respect to the calendar year in which any of the restricted shares vest, Grantee will include in his or her gross income for federal, state and local income tax purposes the fair market value of the restricted shares that vested.

(b) The grant of restricted shares is special incentive compensation that will not be taken into account as "wages" or "salary" in determining the amount of payment or benefit to Grantee under any other compensation or insurance plan of the Company, including without limitation the Third Amended and Restated XTO Energy Inc. Management Group Employee Severance Protection Plan (as the same may be amended from time to time or any successor thereto, the "Management Plan") and the Third Amended and Restated XTO Energy Inc. Employee Severance Protection Plan (as the same may be amended from time to time or any successor thereto, the "Employee Plan").

(c) The Company may hold the certificate for unvested restricted shares until the restricted shares vest or the restricted shares may be uncertificated shares issued in the name of the Grantee and held in a restricted account by the Company's transfer agent. As contemplated and permitted by the provisions of Section 4.04 of the Management Plan and Section 4.02 of the Employee Plan as such plans are currently in effect, the unvested restricted shares granted herein, and all other Awards (as defined in the Plan) previously granted by the Company to Grantee under the Plan, are subject to adjustment as and to the extent provided in Sections 5(f) and 19 of the Plan in the sole discretion of the Committee, subject only to the restrictions on the Committee's discretion specifically set forth in this Agreement and prior Award agreements.

(d) Grantee may pay to the Company any federal, state or local tax withholding owed as a result of the restricted shares vesting with shares of Common Stock owned by Grantee on the date of vesting or with the shares of unrestricted Common Stock acquired upon vesting (the shares of Common Stock being valued at fair market value on the date of vesting).

4. **Death or Disability**. Upon death of Grantee, or upon termination of Grantee's employment by reason of permanent disability (as determined by the Committee), all unvested restricted shares granted herein will immediately vest.

5. **Other Terms, Conditions and Provisions**. As noted above, just as with all other Awards granted to Grantee under the Plan, the restricted shares herein granted by the Company to Grantee are granted subject to all of the terms, conditions and provisions of the Plan, including without limitation the Committee discretion reserved in the adjustment provisions of Sections 5(f) and 19 of the Plan. Grantee hereby acknowledges receipt of a copy of the Plan and Plan prospectus and hereby

consents to receive any updates to the Plan or Plan prospectus electronically. The parties agree that the entire text of the Plan is incorporated by reference as if copied herein. Reference is made to the Plan for a full description of the rights of Grantee and the limitations thereon set forth in the terms, conditions and provisions of the Plan applicable to the restricted shares granted herein. If any of the provisions of this Agreement or of the Management Plan, the Employee Plan or any other compensation or insurance plan of the Company vary from or are in conflict with the Plan, the provisions of the Plan will be controlling.

6. **Non−Transferability**. The restricted shares granted herein are not transferable or assignable by Grantee.

7. **Rights as a Stockholder**. Grantee will have the voting, dividend, and other rights of stockholders of the Company prior to and upon vesting of the restricted shares. If the restricted shares are canceled, all such rights will then be canceled.

8. **No Employment Commitment**. Grantee acknowledges that neither the grant of restricted shares nor the execution of this Agreement by the Company will be interpreted or construed as imposing upon the Company any obligation to retain Grantee’s services for any stated period of time, which employment will continue to be at the pleasure of the Company at such compensation as it determines, unless otherwise provided in a written employment agreement signed by the Company and Grantee.

IN WITNESS WHEREOF, this Agreement is executed and entered into effective on the day and year first above expressed.

XTO ENERGY INC.

By: ______________________________
Name: Bob R. Simpson
Title: Chairman of the Board

GRANTEE

____

Exhibit 10.37

FOURTH AMENDED AND RESTATED

XTO ENERGY INC.

MANAGEMENT GROUP EMPLOYEE SEVERANCE PROTECTION PLAN

WHEREAS, the Amended and Restated XTO Energy Inc. Management Group Employee Severance Protection Plan (the "Prior Plan") was adopted by the Board acting on behalf of the Company, effective as of August 20, 2002, and amended and restated effective as of August 15, 2006 and November 18, 2008;

WHEREAS, the Company, Parent and Merger Sub have entered into an Agreement and Plan of Merger, dated as of the 13th day of December, 2009 (the "Merger Agreement"), pursuant to which Merger Sub will be merged with and into the Company (the "Merger") and, as a result of which, the Company will become a wholly−owned subsidiary of Parent;

WHEREAS, in connection with, and subject to the consummation of, the Merger, the Board has determined that it is in the best interests of the Company to amend and restate the Third Amended and Restated XTO Energy Inc. Management Group Employee Severance Protection Plan, effective as of the Effective Date, to provide additional retention incentives to Participants and to make certain other related changes as set forth herein;

WHEREAS, pursuant to Section 8.02 of the Prior Plan, the Prior Plan may generally be amended by resolution adopted by two−thirds (2/3) of the Board.

NOW, THEREFORE, in order to fulfill the above purposes, the following plan has been developed and is hereby adopted.

ARTICLE I.

EFFECTIVE DATE

The Plan shall become effective as of the date immediately prior to the Effective Date and as of such date shall amend and restate the Third Amended and Restated XTO Energy, Inc. Management Group Employee Severance Protection Plan. The "Effective Date" shall mean the date on which occurs the Effective Time (as defined in the Merger Agreement). In the event that the Effective Time does not occur, the Plan shall not become effective, all of the terms and provisions set forth herein shall be null and void and all of the terms and provisions of the Third Amended and Restated XTO Energy Inc. Management Group Employee Severance Protection Plan as in effect immediately prior to the Effective Date shall remain in full force and effect.

ARTICLE II.

DEFINITIONS

As used herein, the following words and phrases shall have the following respective meanings unless the context clearly indicates otherwise.

Section 2.01 Base Salary. The Participant's base salary or base wages immediately prior to the Effective Date.

Section 2.02 Board. The Board of Directors of the Company.

Section 2.03 Bonus Amount. An amount equal to (i) the greater of the Participant's two most recent regular bonuses, if any, paid in the twelve (12) months prior to the Effective Date, multiplied by two (2), plus (ii) the amount, if any, of the Participant's monthly car allowance immediately prior to the Effective Date, multiplied by twelve (12), plus (iii) the amount, if any, of any "Special Bonuses" awarded to the Participant during the three (3) years preceding the Effective Date. A "Special Bonus" includes any bonus paid as a result of extraordinary performance by a Participant but does not include any bonus paid related to moving expenses or as a sign−on bonus.

Section 2.04 Cash Bonus. An amount equal to the amount of the regular cash bonus paid to the Participant by the Employer in December 2009, excluding any Special Bonus.

Section 2.05 Cause. The Employer shall have "Cause" to terminate a Participant if the Participant (i) willfully and continually fails to substantially perform his or her duties with the Employer (other than a failure resulting from the Participant's incapacity due to physical or mental illness) which failure continues for a period of at least thirty (30) days after a written notice of demand for substantial performance has been delivered to the Participant specifying the manner in which the Participant has failed to substantially perform, or (ii) willfully engages in illegal conduct, gross misconduct, or a clearly established violation of the Employer's written policies and procedures, which is demonstrably and materially injurious to the Employer, monetarily or otherwise; provided, however, that no termination of the Participant's employment shall be for Cause until (x) there shall have been delivered to the Participant a copy of a written notice specifying in detail the particulars of the Participant's conduct which violates either (i) or (ii) above, (y) the Participant shall have been provided an opportunity to be heard by the Board (with the assistance of the Participant's counsel if the Participant so desires), and (z) a resolution is adopted in good faith by two−thirds (2/3) of the Board confirming said violation. No act, nor failure to act, on the Participant's part, shall be considered "willful" unless he or she has acted or failed to act with an absence of good faith and without a reasonable belief that his or her action or failure to act was in the best interest of the Employer. Notwithstanding anything contained in the Plan to the contrary, no failure to perform by the Participant after Notice of Termination is given by or to the Participant shall constitute Cause.

Section 2.06 Code. The Internal Revenue Code of 1986, as amended.

Section 2.07 Company. XTO Energy Inc., a Delaware corporation.

Section 2.08 Employer. The Company and any Subsidiary of the Company which adopts this Plan as a Participating Employer. With respect to a Participant who is not an employee of the Company, any reference under this Plan to such Participant's "Employer" shall refer only to the employer of the Participant, and in no event shall be construed to refer to the Company as well.

Section 2.09 Good Reason. "Good Reason" shall mean the occurrence of any of the following events or conditions:

(a) a material diminution in the Participant's authority, duties, or responsibilities from those in effect on the Effective Date (after giving effect to the Merger), except in connection with the termination of the Participant's employment for Cause, as a result of the Participant's death or incapacity due to physical or mental illness, or by the Participant other than for Good Reason;

(b) any reduction in the Participant's Base Salary during the twelve (12) month period following the Effective Date;

(c) in the case of any Participant described in Section 2.19(c), the failure of the Employer to pay any regular semi−annual bonus during the twelve (12) month period following the Effective Date, subject to the Participant's continued employment to the applicable date;

(d) the Employer's requiring the Participant (without the consent of the Participant) to be based at any location outside a twenty−five (25) mile radius of his or her Place of Employment, except for reasonably required travel on the Employer's business which is not materially greater than such travel requirements during the 12 month period prior to the Effective Date.

The Participant must provide notice to the Employer of the existence of the condition constituting "Good Reason" within a period not to exceed ninety (90) days of the initial existence of the condition, upon the notice of which the Employer must be provided a period of at least thirty (30) days during which it may remedy the condition and, if such condition is so remedied within such period, the Participant shall not have the right to terminate his or her employment for Good Reason. The separation from service must occur within the first two (2) years following the initial existence of one or more of the Good Reason conditions arising without the consent of the Participant.

Section 2.10 Management Group Employee. Each employee of the Employer or any Subsidiary who has been designated by his or her Employer, on or prior to the Effective Date, as a member of the Management Group or the Management Group II, except for any such employees that (i) are subject to, as of the Effective Date, or enter into after the Effective Date, a written employment or consulting contract with the Employer or Parent, (ii) are hired after December 13, 2009, except to the extent the newly hired employee is replacing a former employee who would have been a Participant if his or her employment continued through the Effective Date or (iii) are promoted after December 13, 2009 except to the extent the promoted employee was a Management Group Employee immediately prior to the promotion or is replacing a former employee who would have been a Participant if his or her employment continued through the Effective Date.

Section 2.11 Merger Sub. ExxonMobil Investment Corporation, a Delaware corporation and a wholly−owned subsidiary of Parent.

Section 2.12 Notice of Termination. A notice indicating the specific provisions in the Plan relied upon as the basis for any termination of employment, which sets forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of the Participant's employment under the provision so indicated. No purported termination of employment shall be effective without such Notice of Termination.

Section 2.13 Parent. Exxon Mobil Corporation, a New Jersey corporation.

Section 2.14 Participant. A Management Group Employee who meets the eligibility requirements of Article III.

Section 2.15 Participating Employer. A Subsidiary of the Company which adopts this Plan in accordance with Section 8.04 below.

Section 2.16 Place of Employment. The principal location of the Participant’s employment, determined immediately prior to the Effective Date.

Section 2.17 Plan. This Fourth Amended and Restated XTO Energy Inc. Management Group Employee Severance Protection Plan, as it may be amended from time to time.

Section 2.18 Plan Benefit. The benefits payable in accordance with Article IV of the Plan.

Section 2.19 Retention Benefit An amount in cash equal to:

(a) for Participants who, immediately prior to the Effective Date, were either an Executive Vice President or a Senior Vice President of the Company, two and one−half (2−1/2) times the sum of (i) the Participant’s Base Salary and (ii) the Bonus Amount;

(b) for Participants (other than those described in (a) above) who, immediately prior to the Effective Date, were officers of the Company, two (2) times the sum of (i) the Participant’s Base Salary and (ii) the Bonus Amount; and

(c) for all other Participants, one and one−half (1.5) times the sum of (i) the Participant’s Base Salary and (ii) the Bonus Amount.

Section 2.20 Separation. A “separation from service,” as defined in Code Section 409A.

Section 2.21 Severance Benefit. The benefits payable in accordance with Section 4.02 of the Plan.

Section 2.22 Subsidiary. Any subsidiary of the Company, and any wholly or partially owned partnership, joint venture, limited liability company, corporation, and other form of investment by the Company.

A pronoun or adjective in the masculine gender includes the feminine gender, and the singular includes the plural, unless the context clearly indicates otherwise.

ARTICLE III.

ELIGIBILITY AND PARTICIPATION

Section 3.01 Participation. Each Management Group Employee who continues in the employment of the Company as of the Effective Date shall automatically become a Participant in the Plan as of the day immediately prior to the Effective Date.

Section 3.02 Duration of Participation. A Participant shall cease to be a Participant in the Plan upon the first to occur of: (i) the date he or she ceases to be a Management Group Employee; (ii) the date his or her employment is terminated under circumstances where he or she is not entitled to a benefit under the terms of Article IV of the Plan; or (iii) the date on which he or she has received all of the benefits to which he or she is entitled under the Plan.

ARTICLE IV.

BENEFITS

Section 4.01 Retention Benefits. Each Participant shall be entitled to receive a cash amount equal to his or her Retention Benefit. Subject to acceleration as provided herein, one−half (1/2) of the Retention Benefit shall be paid to the Participant, subject to his or her continued employment to the applicable payment date, on each of (i) the date that is six (6) months after the Effective Date and (ii) the date that is twelve (12) months after the Effective Date.

Section 4.02 Severance Benefits. If a Participant incurs a Separation during the two (2)−year period following the Effective Date either (A) by the Employer without Cause, (B) by the Participant for Good Reason or (C) solely with respect to the benefit provided in Section 4.02(c) below, as a result of death or permanent disability, the Participant shall be entitled to the following:

(a) A lump sum cash payment, payable within ten (10) days after the date of Separation, equal to:

(i) for Participants described in Section 2.19(a) or (b) hereof, the sum of (1) any unpaid Base Salary for the period prior to the Separation; and (2) the unpaid amount of the Retention Benefit; and

(ii) for Participants described in Section 2.19(c) hereof, the sum of (1) any unpaid Base Salary for the period prior to the Separation; (2) the unpaid amount of the Retention Benefit; and (3) an amount equal to the last regular semi−annual bonus received by the Participant on or prior to December 31, 2009.

(b) For a period of eighteen (18) months after the Separation, the Employer shall, at its sole expense, continue on behalf of the Participant and his or her covered dependents and beneficiaries, all medical, dental and vision coverage provided to the Participant immediately prior to the Separation, subject to the Participant’s timely election of COBRA. The benefits provided in this Section 4.02(b) shall be no less favorable to the Participant, in terms of amounts, deductibles and costs to him or her, than the coverage provided to active employees of the Company. The Employer’s obligation hereunder to provide a benefit shall terminate if the

Participant obtains comparable coverage from a subsequent employer. For purposes of the preceding sentence, benefits will not be comparable during any waiting period for eligibility for such benefits or during any period during which there is a preexisting condition limitation on such benefits. The Employer shall also make a lump sum cash payment equal to the amount of any additional income tax payable by the Participant and attributable to the benefits provided under this Section 4.02(b) at the time such tax is imposed. In the event that the Participant's participation in any such coverage is barred under the general terms and provisions of the plans and programs under which such coverage is provided, or any such coverage is discontinued or the benefits thereunder become less favorable than the benefits in effect for active employees of the Company, the Employer shall provide benefits to the Participant, or ensure that such benefits are provided to the Participant, that are no less favorable than the benefits provided to active employees of the Company. At the end of the period of coverage set forth above, the Participant shall have the option to have assigned to him or her at no cost to the Participant and with no apportionment of prepaid premiums, any assignable insurance owned by the Employer and relating specifically to the Participant, and the Participant shall be entitled to all health and similar benefits that are or would have been made available to him or her under law.

Notwithstanding Section 2.01, for purposes of Section 4.02, "Base Salary" shall mean the greater of the Participant's base salary on (i) the Effective Date and (ii) the date of Separation (without regard to any reduction thereof after the Effective Date).

(c) Full vesting of all Converted Equity Awards (as defined below). All stock options that become vested pursuant to the immediately preceding sentence shall remain outstanding through their scheduled expiration date.

Notwithstanding any other provision of the Plan, the sale, divestiture, or other disposition of a Subsidiary shall not be deemed to be a Separation with respect to Participants employed by such Subsidiary, and such Participants shall not be entitled to benefits from the Company or any Participating Employer under the Plan as a result of such sale, divestiture, or other disposition, or as a result of any subsequent termination of employment; provided, however, that for purposes of Section 4.02(c) above, such sale, divestiture or disposition shall be treated as a Separation with respect to such Participants.

Section 4.03 Treatment of Equity Awards Upon Effective Date. The Company and Parent hereby acknowledge and agree that all stock options, restricted shares, performance shares and other equity or equity−based awards to acquire shares of the Company's common stock held by the Participants that were outstanding immediately prior to the Effective Date shall be converted into awards to acquire shares of Parent common stock as of the Effective Date (collectively, the "Converted Equity Awards"), pursuant to the terms and conditions set forth in the Merger Agreement, and for those equity awards which are not vested as of the time of the Merger, such awards shall vest in accordance with their normal vesting schedule, subject to Section 4.02(c) hereof.

Section 4.04 Mitigation or Set−off of Amounts Payable Hereunder. The Participant shall not be required to mitigate the amount of any payment provided for in this Article IV by seeking other employment or otherwise, and except at otherwise provided in Section 4.02(b), nor shall the amount of any payment provided for in this Article IV be reduced by any compensation earned by the Participant as the result of employment by another employer after the date of

Separation or otherwise. The Employer's and Parent's obligations hereunder also shall not be affected by any set−off, counterclaim, recoupment, defense, or other claim, right or action which the Employer or Parent may have against the Participant.

Section 4.05 Parent's Guarantee of Payment and Benefits. In the event that the Participant is entitled to receive any payment or benefit under the Plan from the Employer and the Employer fails to make or provide such payment or benefit, Parent shall promptly satisfy the obligation of the Employer to make or provide such payment or benefit.

Section 4.06 Code Section 409A; Delay of Payments. The terms of the Plan have been designed to comply with or be exempt from the requirements of Code Section 409A, where applicable, and shall be interpreted and administered in a manner consistent with such intent. Notwithstanding anything to the contrary in the Plan, (i) if upon the Participant's Separation, the Participant is a "specified employee" within the meaning of Code Section 409A, and the deferral of any amounts otherwise payable under the Plan as a result of the Participant's Separation is necessary in order to prevent any accelerated or additional tax to the Participant under Code Section 409A, then the Employer shall delay the payment of any such amounts hereunder until the date that is six (6) months following the Separation, at which time any such delayed amounts will be paid to the Participant in a single lump sum, with interest from the date otherwise payable, at the prime rate as published in The Wall Street Journal on the date of Separation, and (ii) if any other payments of money or other benefits due to the Participant hereunder could cause the application of an accelerated or additional tax under Code Section 409A, such payments or other benefits shall be delayed if such delay will make such payment or other benefits compliant under Code Section 409A.

ARTICLE V.

TERMINATION OF EMPLOYMENT

Section 5.01 Written Notice Required. Any purported termination of employment, either by the Employer or by the Participant, shall be communicated by written Notice of Termination to the other.

Section 5.02 Date of Separation. In the case of the Participant's death, the Participant's date of Separation shall be his or her date of death. In all other cases, the Participant's date of Separation shall be the date specified in the Notice of Termination, subject to the following:

(a) If the Participant's employment is terminated by the Employer for Cause, the date specified in the Notice of Termination; and

(b) If the Participant terminates his or her employment for Good Reason: (i) the Notice of Termination shall be given to the Employer within ninety (90) days after the occurrence of the event or condition on which the Participant may terminate his or her employment for Good Reason; (ii) upon receipt of the Notice of Termination, the Employer must be provided a period of at least thirty (30) days during which it may remedy the condition; and (iii) the Participant's date of Separation shall be no earlier than thirty (30) days after the Employer's receipt of the Notice of Termination, but no later than two (2) years after the initial occurrence of the event or condition constituting Good Reason.

ARTICLE VI.

EXCISE TAXES

Section 6.01 In the event it shall be determined that any payment or distribution of any type to or for the Participant's benefit, or any provision for vesting of any equity award held by a Participant, in either case in connection with the Merger, whether payable pursuant to the Plan or otherwise (the "Total Payments"), would be subject to the excise tax imposed by Code Section 4999 or any interest or penalties with respect to such excise tax (such excise tax, together with any such interest and penalties, is collectively referred to as the "Excise Tax"), then the amount of the Total Payments shall be reduced, so that the aggregate present value of all payments in the nature of compensation to the Participant (or for the Participant's benefit) which are contingent on a change of control (as defined in Code Section 280G(b)(2)(A)) is the maximum amount of payments that could be made without the imposition of the Excise Tax. To the extent the Total Payments must be reduced in accordance with this Section 6.01, the portion of the Total Payments that do not constitute deferred compensation within the meaning of Code Section 409A shall first be reduced (if necessary, to zero), and the remainder of the Total Payments shall thereafter be reduced (if necessary, to zero).

Section 6.02 All determinations contemplated by this Section 6 shall be made by the accounting firm acting as the Company's independent auditor immediately prior to the Effective Date (the "Accounting Firm"), which shall provide detailed supporting calculations to the Participant, the Company and Parent within fifteen (15) business days after requested by the Participant or the Company. If the Accounting Firm determines that no Excise Tax is payable by the Participant, it shall furnish an opinion to the Participant that he or she has substantial authority not to report any Excise Tax on his or her federal income tax return. Any determination by the Accounting Firm shall be binding upon the Participant, the Company and Parent.

ARTICLE VII.

SUCCESSORS

Section 7.01 Successors. The Plan shall bind any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company or Parent, as applicable, in the same manner and to the same extent that the Company or Parent would be obligated under the Plan if no succession had taken place. In the case of any transaction in which a successor would not, by the foregoing provision or by operation of law, be bound by the Plan, the Company or Parent, as applicable, shall require such successor expressly and unconditionally to assume and agree to perform the Company's or Parent's obligations under the Plan, in the same manner and to the same extent that the Company or Parent would be required to perform if no such succession had taken place. As used in the Plan, (i) the "Company" shall mean the Company as hereinbefore defined and any successor to its business and/or assets and (ii) "Parent" shall mean Parent as hereinbefore defined and any successor to its business and/or assets. In addition, a successor shall also include any other person or entity which otherwise becomes bound by all of the terms and provisions of the Plan by operation of law.

ARTICLE VIII.

DURATION, AMENDMENT, PLAN TERMINATION AND ADOPTION BY SUBSIDIARIES

Section 8.01 Duration. The Plan shall continue in full force and effect, and shall not terminate or expire, until after all Participants who have become entitled to a Plan Benefit hereunder shall have received all of such benefits in full.

Section 8.02 Amendment and Termination. Prior to the Effective Date, the Plan may be terminated or amended in any respect by resolution adopted by two−thirds (2/3) of the Board. On and after the Effective Date, the Plan shall not be subject to amendment, change, substitution, deletion, revocation, or, except as provided in Section 8.01 above, termination in any respect whatsoever; provided, however, that the Board may amend, change, substitute, delete, revoke, or otherwise modify the terms of the Plan if the Board determines, in its sole discretion, that such amendment, change, substitution, deletion, revocation or modification is necessary for purposes of compliance with or exemption from the requirements of Code Section 409A or applicable law.

Section 8.03 Form of Amendment. The form of any amendment or termination of the Plan shall be a written instrument signed by a duly authorized officer or officers of the Company, certifying that the amendment or termination has been approved by the Board.

Section 8.04 Adoption by Subsidiaries. Any Subsidiary of the Company may, with the approval of the Board, adopt and become an Employer under the Plan by executing and delivering to the Company an appropriate instrument agreeing to be bound as an Employer by all of the terms of the Plan (as it may be amended from time to time) with respect to its eligible employees. The adoptive instrument may contain such changes and amendments in the terms and provisions of the Plan as adopted by such Subsidiary as may be desired by such Subsidiary and acceptable to the Company. The adoptive instrument shall specify the effective date of such adoption of the Plan and shall become as to such adopting Subsidiary a part of the Plan. Notwithstanding the foregoing, any Subsidiary of the Company that was a Participating Employer in the Prior Plan immediately prior to the Effective Date will automatically, without further action of the part of such Subsidiary, be a Participating Employer in the Plan.

ARTICLE IX.

MISCELLANEOUS

Section 9.01 Participant’s Legal Expenses. The Company agrees to pay, upon written demand therefor by the Participant, all legal fees and expenses which the Participant may reasonably incur as a result of any dispute or contest by or with the Company, the Employer or Parent, as applicable, regarding the validity or enforceability of, or liability under, any provision hereof (including as a result of any contest about the amount of any payment pursuant to Article IV), plus in each case interest at the “applicable Federal rate” (as defined in Code Section 1274(d)), provided that the claims asserted by the Participant are substantially upheld by a court of competent jurisdiction after the exhaustion of all appeals. In any such action brought by a Participant for damages or to enforce any provisions hereof, he or she shall be entitled to seek both legal and equitable relief and remedies, including, without limitation, specific performance of the Company’s, the Employer’s or Parent’s obligations hereunder, as applicable, in his or her sole discretion.

Section 9.02 Employment Status. The Plan does not constitute a contract of employment or impose on the Employer any obligation to retain a Participant as an employee, to change the status of a Participant's employment as a Management Group Employee, or to change any employment policies of the Employer.

Section 9.03 Validity and Severability. The invalidity or unenforceability of any provision of the Plan shall not affect the validity or enforceability of any other provision of the Plan, which shall remain in full force and effect, and any prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

Section 9.04 The Participant's Heirs, etc. The Plan shall inure to the benefit of and be enforceable by the Participant's personal or legal representatives, executors, administrators, successors, heirs, distributees, devisees, and legatees. If the Participant should die while any amounts would still be payable to him or her hereunder as if he or she had continued to live, all such amounts, unless otherwise provided herein, shall be paid in accordance with the terms hereof to his or her designee or, if there be no such designee, to his or her estate.

Section 9.05 Governing Law. The validity, interpretation, construction, and performance of the Plan shall in all respects be governed by the laws of the State of Texas.

Section 9.06 Choice of Forum. A Participant shall be entitled to enforce the provisions of the Plan in any state or Federal court located in the State of Texas, in addition to any other appropriate forum.

Section 9.07 Notice. For the purposes hereof, notices and all other communications provided for herein shall be in writing and shall be deemed to have been duly given (i) when hand delivered or (ii) five (5) days after being mailed by United States registered or certified mail, return receipt requested, postage prepaid, addressed to the Company at its principal place of business and to the Participant at his or her address as shown on the records of the Company, provided that all notices to the Company shall be directed to the attention of the Chief Executive Officer of the Company with a copy to the General Counsel of the Company, or to such other in writing in accordance herewith, except that notices of change of address shall be effective only upon receipt.

Section 9.08 Withholding. All amounts paid to a Participant under the Plan shall be reduced by applicable state and Federal tax withholdings and any other withholdings required by applicable law.

[Signature page follows]

IN WITNESS WHEREOF, XTO Energy Inc. has caused these presents to be executed by its duly authorized officer on the 13 th day of December, 2009, to be effective as set forth in Article I.

XTO ENERGY INC.

By: /s/ Vaughn O. Vennerberg, II
Name: Vaughn O. Vennerberg, II
Title: President

EXHIBIT 12.1

XTO ENERGY INC.

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(in millions, except ratios)	Year Ended December 31 2009	2008	2007	2006	2005
Income before income tax	$3,163	$3,026	$2,642	$2,961	$1,810
Interest expense	525	494	267	182	154
Interest portion of rentals	4	5	5	7	8
Earnings before provision for taxes and fixed charges	$3,692	$3,525	$2,914	$3,150	$1,972
Interest expense	$ 525	$ 494	$ 267	$ 182	$ 154
Capitalized interest	42	39	30	18	6
Interest portion of rentals	4	5	5	7	8
Total Fixed Charges	$ 571	$ 538	$ 302	$ 207	$ 168
Ratio of Earnings to Fixed Charges	6.5	6.6	9.6	15.2	11.7

EXHIBIT 21.1

SUBSIDIARIES OF XTO ENERGY INC.

	Jurisdiction of Incorporation
Barnett Gathering, LP	Texas
Cross Timbers Energy Services, Inc.	Texas
Fayetteville Gathering Company	Arkansas
HHE Energy Company	Delaware
HPC Acquisition Corporation	Delaware
HPT, Inc.	Delaware
Mountain Gathering, LLC	Delaware
Nesson Gathering System, LLC	Delaware
Ringwood Gathering Company	Delaware
Summit Gas Gathering, LLC	Delaware
Timberland Gathering & Processing Company, Inc.	Texas
Trend Gathering & Treating, LP	Texas
WTW Properties, Inc.	Texas
XH, LLC	Delaware
XTO Netherlands, Ltd.	Delaware
XTO Offshore Inc.	Delaware
XTO Resources I GP, LLC	Delaware
XTO Resources I LP, LLC	Delaware
XTO UK, Ltd.	United Kingdom

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
XTO Energy Inc.:

We consent to the incorporation by reference in registration statements (Nos. 333−122767, 333−123402 and 333−160070) on Form S−3 and (Nos. 333−68775, 333−69977, 333−37668, 333−81849, 333−91460, 333−120540, 33−55784 and 333−152016) on Form S−8 of XTO Energy Inc. of our report dated February 24, 2010, with respect to the consolidated balance sheets of XTO Energy Inc. as of December 31, 2009 and 2008, and the related consolidated statements of income, stockholders' equity, cash flows, and comprehensive income for each of the years in the three−year period ended December 31, 2009, and the effectiveness of internal control over financial reporting as of December 31, 2009, which report appears in the December 31, 2009 Annual Report on Form 10−K of XTO Energy Inc.

Our report refers to a retrospective change in accounting related to determining earnings per share.

Fort Worth, Texas
February 24, 2010

EXHIBIT 23.2

[LETTERHEAD OF MILLER AND LENTS, LTD. APPEARS HERE]

February 24, 2010

XTO Energy Inc.
810 Houston Street
Fort Worth, TX 76102

Re: XTO Energy Inc.
2009 Annual Report on Form 10−K

Gentlemen:

The firm of Miller and Lents, Ltd., consents to the references to our firm in the form and context in which they appear and to the use of our report dated February 17, 2010 regarding the XTO Energy Inc. Proved Reserves and Future Net Revenues as of December 31, 2009, in the 2009 Annual Report on Form 10−K. We further consent to the incorporation by reference of our report in Registration Statements Nos. 333−160070, 333−122767 and 333−123402 on Form S−3, and Registration Statements Nos. 333−68775, 333−69977, 333−37668, 333−81849, 333−91460, 333−120540, 333−152016 and 33−55784 on Form S−8 of XTO Energy Inc.

The subject report was prepared by Miller and Lents, Ltd. for the use of XTO Energy Inc. The analysis, conclusions, and methods contained in the report are based upon information that was in existence at the time the reports were rendered. While the subject report may be used as a descriptive resource, investors are advised that Miller and Lents, Ltd. has not verified information provided by others except as specifically noted in the reports, and Miller and Lents, Ltd. makes no representation or warranty as to the accuracy of information provided by others. Moreover, the conclusions contained in the report are based on assumptions that Miller and Lents, Ltd. believed were reasonable at the time of their preparation and that are described in the report in reasonable detail. However, there are a wide range of uncertainties and risks that are outside of the control of Miller and Lents, Ltd. which may impact these assumptions, including but not limited to unforeseen market changes, actions of governments or individuals, natural events, economic changes, and changes of laws and regulations or interpretation of laws and regulations.

Miller and Lents, Ltd., has no interests in XTO Energy Inc. or in any affiliated companies or subsidiaries and is not to receive any such interest as payment for such reports and has no director, officer, or employee otherwise connected with XTO Energy Inc. We are not employed by XTO Energy Inc. on a contingent basis.

Yours very truly,

MILLER AND LENTS, LTD.

By /s/ James Pearson
James Pearson
Chairman

EXHIBIT 31.1

CERTIFICATIONS

I, Keith A. Hutton, certify that:

1. I have reviewed this annual report on Form 10−K of XTO Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: February 24, 2010

/s/ KEITH A. HUTTON

Keith A. Hutton
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATIONS

I, Louis G. Baldwin, certify that:

1. I have reviewed this annual report on Form 10−K of XTO Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: February 24, 2010

/s/ Louis G. Baldwin
Louis G. Baldwin
Chief Financial Officer

EXHIBIT 32.1

Certification of Chief Executive Officer and Chief Financial Officer of XTO Energy Inc.
(Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes−Oxley Act of 2002)

In connection with the Annual Report of XTO Energy Inc. (the “Company”) on Form 10−K for the period ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Keith A. Hutton, Chief Executive Officer of the Company, and Louis G. Baldwin, Chief Financial Officer of the Company, each hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes−Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ KEITH A. HUTTON

Keith A. Hutton
Chief Executive Officer
February 24, 2010

/s/ LOUIS G. BALDWIN

Louis G. Baldwin
Chief Financial Officer
February 24, 2010

EXHIBIT 99.1

February 17, 2010

XTO Energy Inc.
810 Houston Street, Suite 2000
Fort Worth, TX 76102

Re: XTO Energy Inc. (XTO)
Reserves and Net Revenues Forecast
As of December 31, 2009
SEC Pricing Case

Gentlemen:

At your request, Miller and Lents, Ltd. (MLL) estimated the proved reserves and future net revenues as of December 31, 2009 attributable to the XTO Energy Inc. (XTO) interests in certain properties located primarily in Alaska, Arkansas, Colorado, Kansas, Louisiana, Montana, New Mexico, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming. The properties include approximately 41,105 leases and 64,584 wells.

MLL performed evaluations, which are designated as the SEC Pricing Case, using prices and expenses as specified by XTO and described in detail on Attachment 1. The aggregate results of MLL's evaluations are as follows:

	Net Reserves			Future Net Revenues	
Reserves Category	**Oil and Condensate, MBbls.**	**Natural Gas Liquids, MBbls.**	**Gas, MMcf**	**Undiscounted, M$**	**Discounted at 10% Per Year, M$**
Proved Developed Producing	207,103.3	59,837.3	6,757,221.0	21,416,044.1	12,441,620.9
Proved Developed Nonproducing	5,454.1	2,849.8	596,024.9	1,393,113.1	730,615.3
Proved Undeveloped	81,851.1	30,493.6	5,148,587.1	8,071,568.3	1,910,115.3
Total Proved	**294,408.5**	**93,180.7**	**12,501,833.0**	**30,880,725.5**	**15,082,351.5**
Platform Abandonment Costs				−189,529.3	−121,326.7
Total	**294,408.5**	**93,180.7**	**12,501,833.0**	**30,691,196.2**	**14,961,024.8**

Proved reserves and future net revenues were estimated in accordance with the provisions contained in Securities and Exchange Commission Regulation S−X, Rule 4−10(a). The Securities and Exchange Commission definition of proved reserves is shown on Attachment 2. Gas volumes for each property are stated at the pressure and temperature bases appropriate for the sales contract or state regulatory authority;

therefore, some of the aggregated totals may be stated at a mixed pressure base. No provisions for the possible consequences, if any, of product sales imbalances were included in MLL’s projections since MLL received no relevant data. Estimates of future net revenues and discounted future net revenues are not intended and should not be interpreted to represent fair market values for the estimated reserves. In MLL’s projections, with the exception of the offshore platforms, future costs of abandoning facilities and wells were assumed to be offset by salvage values. Estimated costs, if any, for restoration of producing properties to satisfy environmental standards are beyond the scope of this assignment.

Following Attachment 2 is a list of exhibits that include annual projections of future production and net revenues for the reserves category totals; for the property designations, i.e., operated, non−operated, or royalty; and for the XTO production entities. The annual projections of future production and net revenues for each individual property are included in separate volumes to this report. Those projections are grouped in the volumes by property designation, production entity, and reserves category. The exhibits included herein and the accompanying volumes should not be relied upon independently of this narrative.

The proved developed producing reserves and production forecasts were estimated by production decline extrapolations, water−oil ratio trends, P/Z declines, or in a few cases, by volumetric calculations. For some properties with insufficient performance history to establish trends, MLL estimated future production by analogy with other properties with similar characteristics. These analogies were mostly type curves developed by XTO for specific formations. Type curves are the projection of average monthly production normalized to time zero for a large number of wells producing from a specific formation. The decline characteristics of the type curve are used as a basis for estimating future production and reserves for evaluated wells that do not have adequate production history to establish trends. MLL reviewed these curves and employed them in our evaluations because MLL believes the type curves are the best available indication of future production for some of the evaluated wells. The past performance trends of many properties were influenced by production curtailments, workovers, waterfloods, and/or infill drilling. Actual future production may require that MLL’s estimated trends and/or the type curves be significantly altered.

The estimated proved developed nonproducing reserves can be produced from existing wells, but require expenditures for recompletions, workovers, and/or initial completions and pipeline connection. Recompletions open and produce formations that are currently behind the pipe. Workovers restore wells to production levels prior to wellbore damage or mechanical failures. Initial completions and pipeline connections put wells that have been drilled and logged on production. Proved developed nonproducing reserves estimates were based on analogies with other wells that commercially produce from the same formation or, in a few cases, on volumetric calculations. For some wells that had been damaged by scale buildup or mechanical problems, estimated proved nonproducing reserves assumed that workover operations could restore the wells to production levels prior to the damage. The timing of initial production was provided to MLL by XTO. When actual production history is available for these nonproducing reserves, MLL’s reserves estimates may be significantly revised.

The estimated proved undeveloped reserves require significant capital expenditures such as costs to drill wells or to install secondary and/or tertiary recovery operations. Drilling costs were mainly for infill wells that were evaluated based on analogies to similar infill wells already drilled in the field and/or the production histories of offset wells in the same field. Secondary recovery operations are mainly waterfloods, and tertiary recovery operations are mainly carbon dioxide and/or nitrogen injection projects. Proved undeveloped reserves for these operations were based on analogies with pilots in the same field or production from a nearby field with similar reservoir properties or, in one case, on reports provided by the field operator. The estimated timing of infill drilling and waterflood and tertiary expansions was provided by XTO. As the actual results of the infill wells and waterflood and tertiary installations became available, MLL’s estimates of reserves may be significantly revised.

Reserves estimates from volumetric calculations and from analogies are often less certain than reserves estimates based on well performance obtained over a period during which a substantial portion of the reserves was produced.

Natural gas liquids were estimated for areas with gas production that is processed by gas plants. The gas reserves attributed to this production were reduced to account for the shrinkage associated with the extraction of the liquids.

The data employed in MLL’s estimations of proved reserves and future net revenues were provided by XTO. The current expenses for each lease were obtained from operating statements provided by XTO except for certain leases where XTO deducted items considered by XTO to be nonrecurring expenditures. No overhead was included for those properties operated by XTO. For some properties, such as large waterfloods, XTO assumed a decline in operating costs due to depleting production that was derived by forecasting a decrease in the property well count. For some gas properties, XTO assumed operating costs would be split between a variable component and a fixed component. The variable component was a constant cost per thousand cubic feet of gas production, and the fixed component was a constant cost per well completion. Also, for some properties that XTO operates, operating expenses were reduced due to contractual payments received from non−operators that were greater than the non−operated working interest portion of the expenses. None of the data provided to MLL by XTO, including, but not limited to, graphical representations and tabulations of past production performance, well tests and pressures, ownership interests, prices, and operating costs, were verified by MLL as such was not within the scope of MLL’s assignment.

The evaluations presented in this report, with the exceptions of those parameters specified by others, reflect MLL’s informed judgments based on accepted standards of professional investigation but are subject to those generally recognized uncertainties associated with interpretation of geological, geophysical, and engineering information. Government policies and market conditions different from those employed in this study may cause the total quantity of oil or gas to be recovered, actual production rates, prices received, or operating and capital costs to vary from those presented in this report. Minor precision inconsistencies in subtotals may exist in the report due to truncation or rounding of aggregated values.

Miller and Lents, Ltd. is an independent oil and gas consulting firm. No director, officer, or key employee of Miller and Lents, Ltd. has any financial ownership in XTO Energy Inc. or any related company. MLL’s compensation for the required investigations and preparation of this report is not contingent on the results obtained and reported, and MLL has not performed other work that would affect our objectivity. Preparation of this report was supervised by an officer of Miller and Lents, Ltd., who is a professionally qualified and licensed Professional Engineer in the State of Texas with more than 25 years of relevant experience in the estimation, assessment, and evaluation of oil and gas reserves.

MLL's work papers and data are in our files and available for review upon request. If you have any questions regarding the above, or if we can be of further assistance, please call.

Yours very truly,

MILLER AND LENTS, LTD.
Texas Registered Engineering Firm No. F−1442

By: /s/ JAMES C. PEARSON
James C. Pearson, P.E.
Chairman

JCP/slc

Attachment 1

12/31/09

XTO Energy Inc. (XTO)

SEC PRICING CASE

A.	Oil Price	Average price during the 12−month period prior to 12/31/09 determined as the arithmetical average of the first−day−of−the−month price for each month during the year 2009. The average price was held constant through the life of the property.
B.	Gas/NGL Price	Average price during the 12−month period prior to 12/31/09 determined as the arithmetical average of the first−day−of−the−month price for each month during the year 2009. The average price was held constant through the life of the property.
C.	Operating Costs	Current expenses held constant through the life of the property. For some properties, expenses included a variable component that was a constant cost per unit of gas production and a fixed component that was a constant cost per well completion.
D.	Discount Rate	10% per year.

Reserves Definitions In Accordance With
Securities and Exchange Commission Regulation S−X

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

Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non−productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Proved Oil and Gas Reserves

Proved oil and gas reserves are those quantities of oil and gas, 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, operating methods, and government regulations—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 the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

1. The area of the reservoir considered as proved includes:
   a. The area identified by drilling and limited by fluid contacts, if any, and
   b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
2. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
3. Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
4. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
   a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
   b. The project has been approved for development by all necessary parties and entities, including governmental entities.

5. 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 12−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.

Developed Oil and Gas Reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

1. 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
2. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped Oil and Gas Reserves

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

1. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
2. 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.
3. 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, as defined below, or by other evidence using reliable technology establishing reasonable certainty.

Analogous Reservoir

Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an “analogous reservoir” refers to a reservoir that shares the following characteristics with the reservoir of interest:

1. Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
2. Same environment of deposition;
3. Similar geological structure; and
4. Same drive mechanism.

Reservoir properties must, in aggregate, be no more favorable in the analog than in the reservoir of interest.