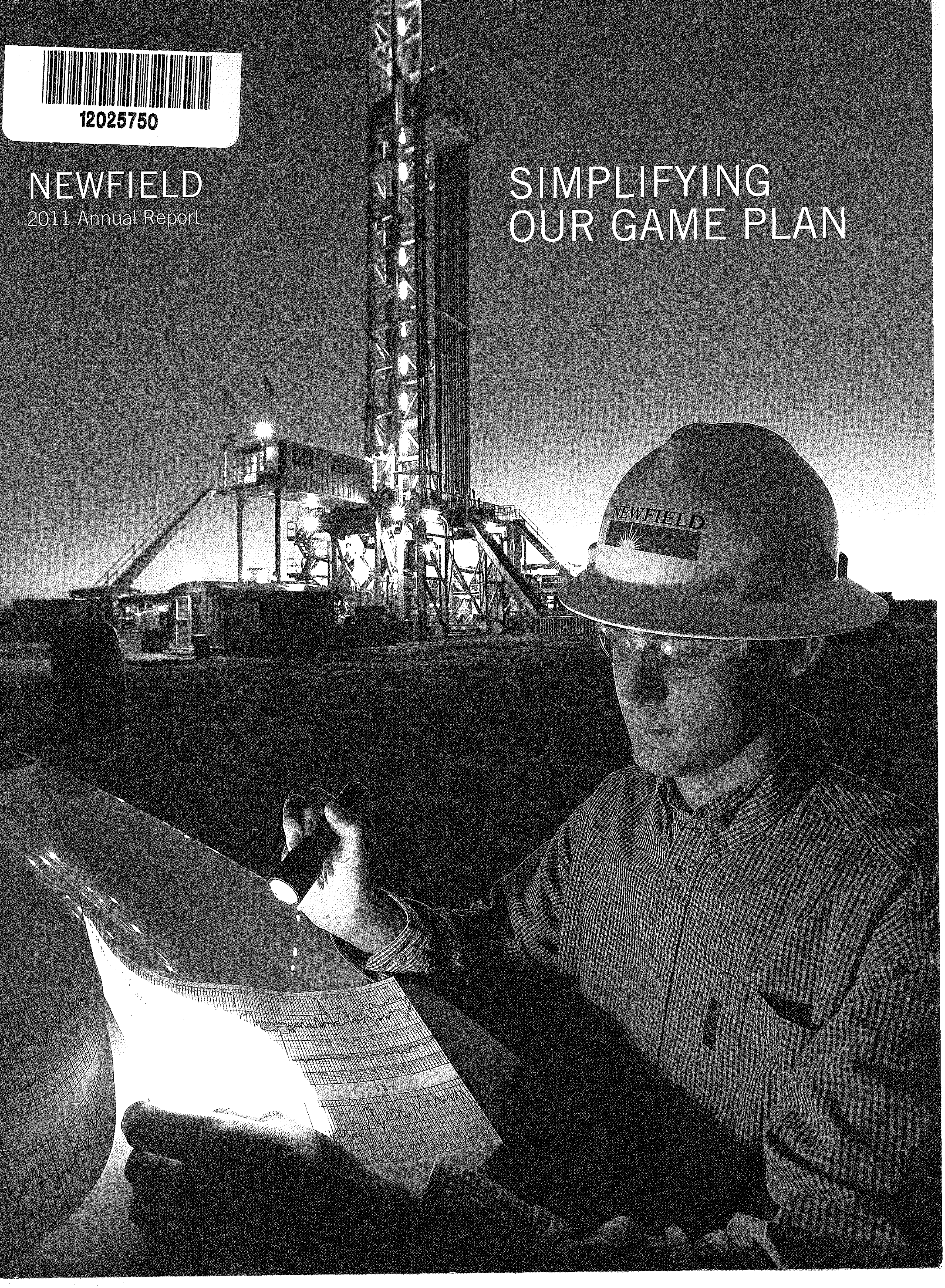
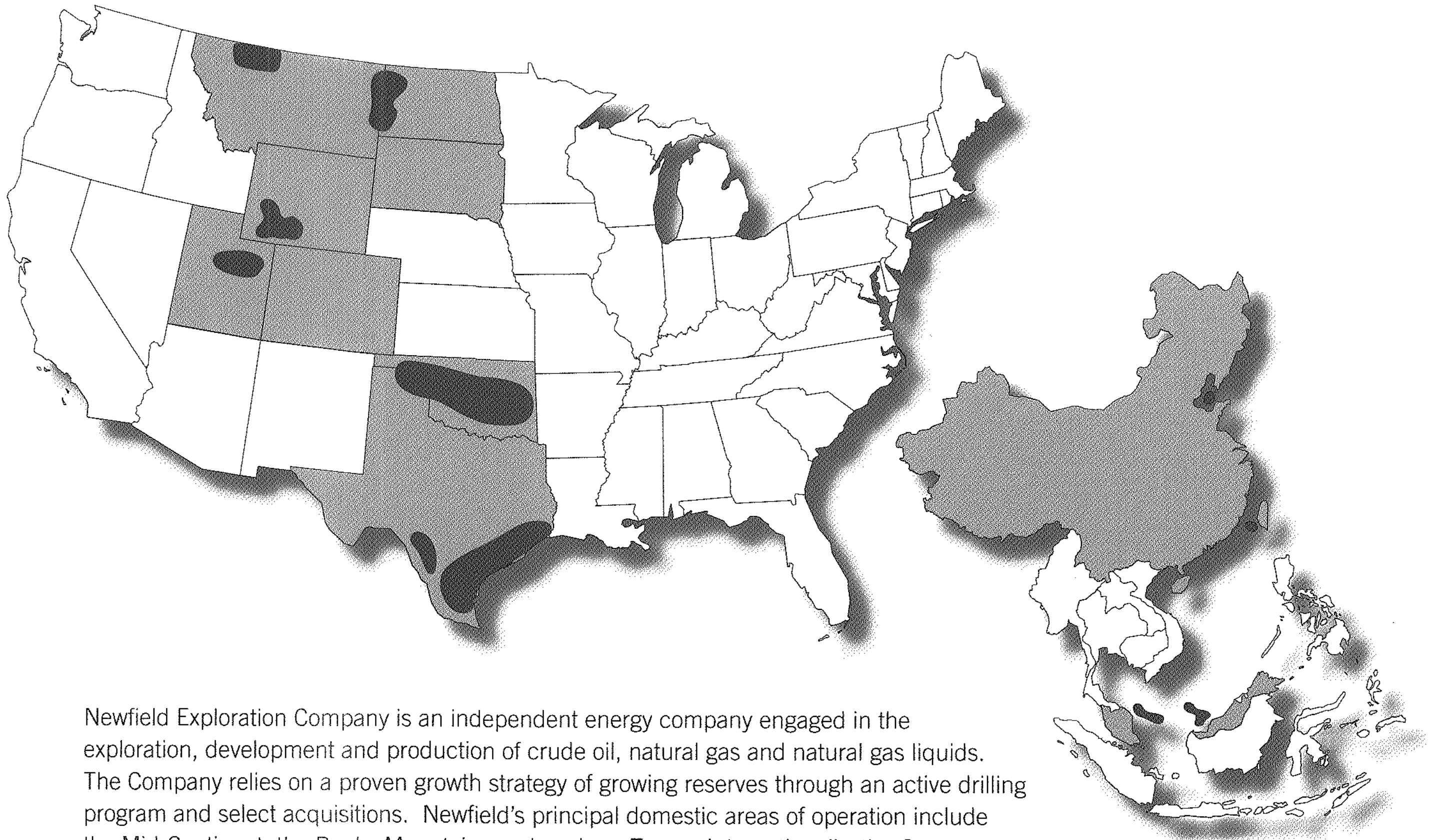
NEWFIELD

2011 Annual Report

SIMPLIFYING OUR GAME PLAN





Newfield Exploration Company is an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. The Company relies on a proven growth strategy of growing reserves through an active drilling program and select acquisitions. Newfield's principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and onshore Texas. Internationally, the Company focuses on offshore oil developments in Malaysia and China.

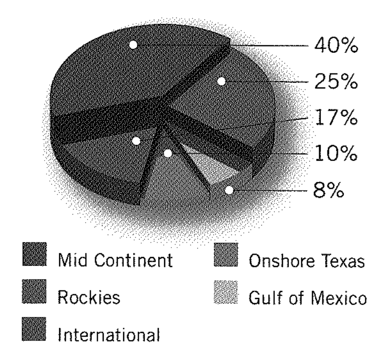
We have a Simple Game Plan:

Provide Organizational Focus: "Focus" is one of our Founding Business Principles and it has been a significant contributor to our success. By monetizing non-strategic assets, we are effectively focusing both people and capital on our best projects.

Align Investments with Internal Resources: Our 2012 investments will be guided by cash flow and we are committed to living within our internal resources. We will manage our balance sheet assuring a strong capital structure and ample liquidity.

Grow Oil Production and Reserves: We believe oil is the best "value proposition" for our capital investments today and for the foreseeable future. Substantially all of our 2012 capital investments are being allocated to oil projects. Our oil and liquids production is expected to grow at least 20% in 2012 and our natural gas production will decline.

2012 Estimated Production— 290 – 300 Bcfe



Build People and Prospects for the Future: We will invest in "Team Newfield" and empower our people to conceive and capture opportunities for the future. We will continue to hire, train and develop the best talent in the business to ensure that they grow in tandem with our assets.

Dear Fellow Stockholders:

The year 2011 fell short of our expectations. Following strong share price performance in 2009 and 2010, our 2011 performance reflected the unique challenges associated with our transition away from natural gas toward higher-margin oil developments. Although not pleased with our share price performance in 2011, I am confident in our people, our asset base and that we are making the right long-term choices to create stockholder value. Our focus will remain on oil and we will build momentum in oil growth through 2012 and entering 2013.

For 2011, Newfield recorded net income of $539 million, or $3.99 per diluted share. Revenues for 2011 were $2.5 billion. Net cash provided by operating activities before changes in operating assets and liabilities was $1.5 billion.

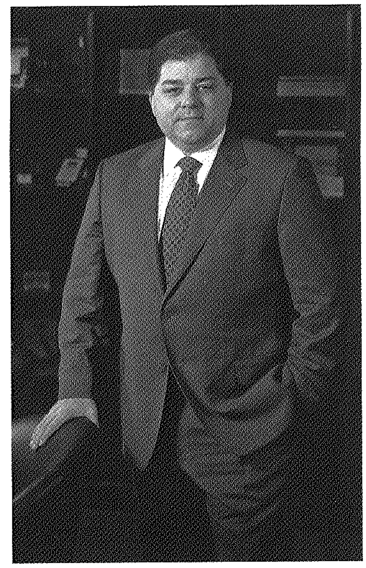
Our focus on oil was evident with our more than 20% growth in oil and liquids production in 2011. Our natural gas volumes declined approximately 5% in 2011 due to reduced capital investments in gas assets and natural field declines. For the full year 2011, we produced approximately 300 Bcfe, or 4% higher than 2010 volumes. On a pro forma basis, excluding the production associated with the sale of non-strategic assets in 2011, full year 2011 production would have been approximately 290 Bcfe.

Increases in service costs, particularly in oil plays like the Bakken and Eagle Ford, reduced margins. We invested approximately $2 billion in 2011 and through cash flow and proceeds from non-strategic asset sales, we kept our balance sheet strong. This is the third consecutive year we have lived within our internal resources.

At year-end 2011, our proved reserves were 3.9 Tcfe (263 MMBbls of oil and 2.3 Tcf of natural gas). Probable reserves were 2.6 Tcfe (151 MMBbls of oil and 1.7 Tcf of natural gas). This reflects growth of 5% and 4%, respectively, over the prior year. By focusing our investments on oil, we have increased our oil/liquids component to 40% of our total proved reserves.

Our proved oil reserves increased nearly 30% during 2011 and our proved natural gas reserves declined by 6% when compared to year-end 2010. The proved developed portion of our reserves is 54%.

Although growing oil production and reserves provides more challenges than natural gas, the superior value proposition today in our oil assets is clear. The present value of our proved reserves (discounted at 10%) increased by more than 20% over the prior year, to a record high. This follows a more than 65% increase in present value during 2010. We are focused on combining profitable growth and long-term value creation for our stockholders.



Lee K. Boothby Chairman, President and CEO

In line with our 2012 simplified game plan, we recently declared our Gulf of Mexico assets "non-strategic" and commenced a process to maximize the value from these properties. To date, our ongoing sale of non-strategic assets has generated approximately $716 million in proceeds (including $406 million of 2011 sales). We are improving our organizational focus and more effectively allocating both people and capital to our best projects.

Other significant 2011 highlights include:

- Captured more than 65,000 net acres north of our Uinta Basin Monument Butte field through several transactions. We now control approximately 230,000 net acres in the Uinta Basin and are developing exciting new oil plays and testing new horizontal concepts. Production from this region is expected to grow more than 20% in 2012.
- Assembled a 125,000 net acre position in the Anadarko Basin's Cana Woodford play. We extended the Cana Woodford south and east of the known fairway and have expanded our footprint in Oklahoma's Woodford Shale play to about 300,000 net acres. We have planned an aggressive assessment drilling program here in 2012.
- Commenced production from new offshore developments in Malaysia and the Gulf of Mexico. In late 2011 / early 2012, we added more than 16,000 BOEPD net production through three developments: East Piatu and Puteri in Malaysia and Pyrenees in the Gulf of Mexico.

▶ Signed two separate long-term supply agreements to ensure 38,000 BOPD in refining capacity for our Uinta Basin oil growth.

On the inside cover of this report, we outlined the components of our "Simplified Game Plan." This plan is designed to ensure superlative execution in 2012 and our people are united and focused on this common goal.

Our 2012 capital budget is $1.5 – $1.7 billion (excluding $210 million in capitalized internal costs), which is approximately 20% less than we invested in 2011. With our continued view that natural gas prices will remain weak in 2012, our overall planned investment levels in natural gas projects have been reduced.

Absolute production growth is not an emphasis in 2012 and production is expected to range from 290 – 300 Bcfe, or flat to slightly higher than 2011 volumes. Substantially all of our budget will be directed toward oil and liquids-rich opportunities. In addition, we may elect to curtail, shut-in and/or defer natural gas production should prices further deteriorate. We recognize that production growth is important to E&P investors, but we will not fund low margin natural gas projects today. Through our growing oil investments, we will strive for higher revenues, increased cash flow per share and improved profitability margins that we believe will increase long-term stockholder value.

We expect to generate more than 20% growth in our 2012 oil and liquids volumes. With natural declines, our natural gas volumes in 2012 will decline as much as 15% below 2011 levels. Because we have a balanced and diversified asset base, we have the flexibility to shift our focus to the commodity or geography offering the highest returns. In light of today's natural gas prices, we are continuing our transition to an "oil company" and expect that oil and liquids will comprise approximately 50% of our production by late 2012, as compared to just 32% of our production coming from oil and liquids in late 2008.

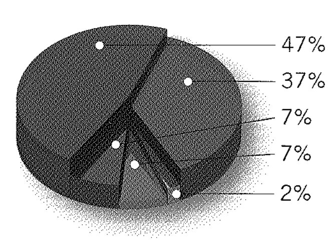
We remain well hedged in 2012 in both oil and gas. More than 60% of our anticipated natural gas production is hedged this year. In 2013, more than 40% of our expected natural gas production is hedged. We have consistently hedged a substantial portion of our production to ensure cash flow to meet our capital program needs.

We expect our oil growth in 2012 to come primarily from the Rocky Mountains (Uinta and Williston basins) and offshore Malaysia. In the Uinta, our efforts are focused on the Central Basin, located north of our Monument Butte field. We will increase our activity in the basin with a seven- to eight-rig program (from our historical four to five rigs) and accelerate our developments to improve returns, grow production and define the true resource and economic potential of this new area.

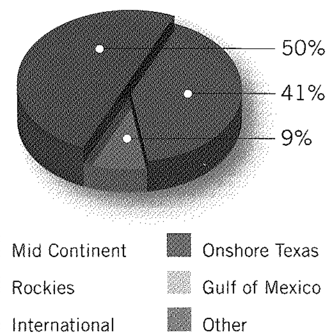
In the Williston Basin, we resumed our activities in early 2012 following a brief slowdown in late 2011. We expect to run up to four operated rigs in this high-return oil play in 2012. Oil production from Malaysia is expected to increase more than 35% in 2012 with new, high-rate fields now on-line. At the time of this letter, our net production in Malaysia was at record levels of nearly 30,000 BOPD.

The year 2012 marks our 24th year in business. As we approach our "silver anniversary" in 2013, it's worth reflecting on what we have created together. Your continued support and investment in our Company is appreciated. We are confident that we are making the right investments today to ensure a bright future and our continued long-term success.

Proved Reserves— 3.9 Tcfe



Probable Reserves— 2.6 Tcfe



Lee K. Boothby

Chairman, President and CEO

Issues and Answers

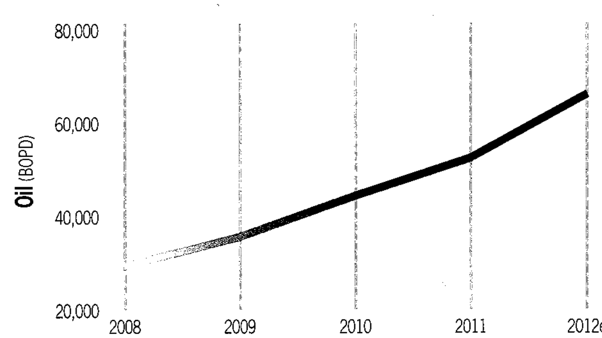
Q: What are Newfield's short- to intermediate-term strategies to create value for its stockholders?

Our investments today are "oil focused." Our portfolio contains oil and liquids-rich assets capable of delivering significant production growth – forecast at more than 20% in 2012. With substantially all of our capital allocated to oil, we are expecting and willing to accept declines in our natural gas production. While we are more optimistic on natural gas prices over the long-term, our analysis shows that they will likely remain weak in 2012. Our efforts are focused on profitable growth while maximizing our revenues and cash flow.

We have an ongoing effort underway to sell non-strategic assets. In 2011, we received proceeds of $406 million for asset sales and an additional $310 million in sales closed in early 2012. In addition, we now view our Gulf of Mexico assets as non-strategic and are pursuing all options to maximize value. These sales are helping to improve our organizational focus and allow us to high-grade our portfolio.

It is important that we continue to build for our future. We have several active assessments underway today that could ultimately become large scale field developments. A recent example is the Cana Woodford oil and liquids-rich play where we recently captured more than 125,000 net acres in the Anadarko Basin of Oklahoma. Combined with our Arkoma Woodford play, we now control approximately 300,000 net acres in the Woodford Shale.

Newfield's (2008-2012e) Net Oil/Liquids Production



Q: How does the Company view its asset portfolio today? Is the "diverse" nature of the assets a strength or distraction?

We believe that a diversified asset portfolio provides strength and high-value optionality with our capital allocation decisions. We have no desire to limit our focus to a single geographic area or basin. Our primary focus today is on long-lived, onshore U.S. resource plays diversified by commodity, product type and a balance of exploration and exploitation risk.

In our domestic resource plays, we effectively share "lessons learned" and best practices in technologies such as drilling and completion. These practices expedite our learning curve advancements, increase efficiencies and allow for timely cost reductions in operations.

In addition, we have attractive oil developments underway offshore Malaysia and China.

Q: Explain Newfield's core competencies. What differentiates your Company from the competition?

Approaching 25 years in the business, our organization is rich with competencies. Our success can be attributed to the adherence to our Founding Principles as they are applied throughout our growing organization.

In our core development plays, we have realized continual improvement in drilling efficiencies. We have pioneered the use of longer lateral completions and have safely reduced our days to total depth in plays like the Woodford, the Bakken and the Uinta Basin. These efficiencies have helped offset the recent increases in completion costs.

We are a skilled asset acquirer and have successfully used acquisitions to enter new regions and build scale in our operations. Since 2000, we have completed six major domestic transactions and proven our ability to "franchise" Newfield's culture to other geographic regions. We have added value in these areas through development of the acquired properties and capturing new opportunities.

Our exploration teams have added large acreage positions in multiple prospective resource plays at attractive entry costs. Over the last three years, we have assembled more than one-million acres in assessment areas including the Maverick, Southern Alberta and Uinta basins. Most recently, we added a large position in the Cana Woodford play in the Anadarko Basin. Due to their scale and resource potential, these plays could become foundational assets for our future growth.

We are proven operators. With both technical and field-level competencies, we prefer to operate our developments to ensure they are conducted effectively, timely, safely and with the utmost regard for the environment.

Q: What is Newfield's view of Corporate Responsibility?

As our organization continues to grow and mature, our commitment to corporate responsibility is expanding. From our actions in the field, to encouraging our workforce to engage in and give back to local communities, we recognize new accountabilities and are working to increase transparency across environment, social and governance (ESG) performance indicators.

For our people and those working on our behalf, we share a commitment to maintain safe operations, minimize environmental impact and conduct daily business with the highest ethical standards. We comply with changing regulatory environments and support the communities in which we live and work. We strive to enhance the economic vitality of these communities through charitable contributions and promoting employee volunteerism.

In 2001, we established the Newfield Foundation. Since its inception, the Foundation has contributed more than $4.2 million to non-profit organizations in social services, environmental, medical, cultural arts and disaster relief efforts.

In 2011, we were among the first exploration and production companies to support the development of state initiatives for public disclosure of hydraulic fracturing chemical information by submitting chemical disclosure data to the Ground Water Protection Council's (GWPC) FracFocus website.

Our efforts on corporate responsibility are outlined in greater detail on our website at **www.newfield.com**.

Q: How is Newfield responding to the major issues facing the industry?

Our industry has seen dramatic transformation over the last several years. The rise of unconventional resource plays has altered our business through the identification of long-lived, economically viable oil and gas resources. Domestically, our industry has reversed a 30-year decline in oil production and we are in the early stages of understanding the true potential of unconventional oil resources. Our push to find and develop new resources of natural gas has led to a near-term overabundance of supply, and when coupled with a weak economy, has depressed prices and challenged rates of return. Fortunately for Newfield, we are able to shift our capital investments toward oil. In the long-term, we are strong advocates of natural gas as our nation's environmentally friendly "fuel of the future."

It is imperative that our nation's leaders embrace the potential of U.S. natural gas and oil resources and work to increase their role in a vibrant economy and as part of our bright domestic energy future. We lack an energy policy in the U.S. and our nation's future will require us to harness all sources of economically-viable and environmentally-sound energy. We need leadership in Washington D.C. and a non-partisan, long-term energy plan that recognizes the enormous value the energy industry brings to the U.S. and world economy. At Newfield, we have taken an active role on these issues and are engaged at both state and federal levels.

Resource plays are more people-intensive than conventional reservoirs. Our industry's ability to find and produce natural resources requires talented people. Attracting both today's graduates and skilled professionals into our industry is required to offset the pending retirement of industry veterans and grow the workforce. We are committed today to building the workforce of tomorrow.

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

Form 10-K

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

For the fiscal year ended December 31, 2011

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: 1-12534

Newfield Exploration Company
(Exact name of registrant as specified in its charter)

Delaware *(State of incorporation)*	**72-1133047** *(I.R.S. Employer Identification No.)*
4 Waterway Square Place, Suite 100, The Woodlands, Texas *(Address of principal executive offices)*	**77380** *(Zip Code)*

Registrant's telephone number, including area code:
(281) 210-5100

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 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) 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 (§ 229.405) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $9.1 billion as of June 30, 2011 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 21, 2012, there were 134,816,136 shares of the registrant's common stock, par value $0.01 per share, outstanding.

Documents incorporated by reference: Proxy Statement of Newfield Exploration Company for the Annual Meeting of Stockholders to be held May 4, 2012, which is incorporated by reference to the extent specified in Part III of this Form 10-K.

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If you are not familiar with any of the oil and gas terms used in this report, we have provided explanations of many of them under the caption "Commonly Used Oil and Gas Terms" at the end of Items 1 and 2 of this report. Unless the context otherwise requires, all references in this report to "Newfield," "we," "us" or "our" are to Newfield Exploration Company and its subsidiaries. Unless otherwise noted, all information in this report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates we prepared and are net to our interest.

Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results, such as planned capital expenditures, the availability and sources of capital resources to fund capital expenditures and other plans and objectives for future operations. Forward-looking information is typically identified by use of terms such as "may," "believe," "expect," "anticipate," "intend," "estimate," "project," "target," "goal," "plan," "should," "will," "predict," "potential" and similar expressions that convey the uncertainty of future events or outcomes. Although we believe that these expectations are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties and risks. Actual results may vary significantly from those anticipated due to many factors, including:

- oil and gas prices and demand;
- operating hazards inherent in the exploration for and production of oil and gas;
- general economic, financial, industry or business trends or conditions;
- the impact of, and changes in, legislation, law and governmental regulations;
- the impact of regulatory approvals;
- the availability of the securities, capital or credit markets and the cost of capital to fund our operations and business strategies;
- the ability and willingness of current or potential lenders, hedging contract counterparties, customers, and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us;
- the availability of transportation and refining capacity for the crude oil we produce in the Uinta Basin;
- drilling risks and results;
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- global events that may impact our domestic and international operating contracts, markets and prices;
- labor conditions;
- weather conditions;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- competitive conditions;
- civil or political unrest in a region or country;
- our ability to monetize non-strategic assets, pay debt and the impact of changes in our investment ratings;
- electronic, cyber or physical security breaches;
- changes in tax rates;
- uncertainties and changes in estimates of reserves;
- the effect of worldwide energy conservation measures;
- the price and availability of, and demand for, competing energy sources; and
- the other factors affecting our business described below under the caption "*Risk Factors*."

All forward-looking statements in this report, as well as all other written and oral forward-looking statements attributable to us or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in this section and elsewhere in this report. See Items 1 and 2, *"Business and Properties,"* Item 1A, *"Risk Factors,"* Item 3, *"Legal Proceedings,"* Item 7, *"Management's Discussion and Analysis of Financial Condition and Results of Operations"* and Item 7A, *"Quantitative and Qualitative Disclosures About Market Risk"* for additional information about factors that may affect our businesses and operating results. These factors are not necessarily all of the important factors that could affect us. Use caution and common sense when considering these forward-looking statements. Unless securities laws require us to do so, we do not undertake any obligation to publicly correct or update any forward-looking statements whether as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise.

PART I

Items 1 and 2. *Business and Properties*

General

Newfield Exploration Company, a Delaware corporation formed in 1988, is an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. Our principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and onshore Texas. Internationally, we focus on offshore oil developments in Malaysia and China.

Through our website, *www.newfield.com*, you can access, free of charge, electronic copies of our governing documents, including our Board of Directors' Corporate Governance Principles and the charters of the committees of our Board of Directors, in addition to the documents we file with the U.S. Securities and Exchange Commission (SEC), including our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K. You also may request printed copies of our SEC filings or governance documents free of charge by writing to our corporate secretary at the address on the cover of this report. Information contained on our website is not incorporated herein by reference and should not be considered part of this report.

In addition, the public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site (*www.sec.gov*) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Our Founding Business Principles

We are guided by our founding business principles. These principles are the foundation for our success and are practiced every day in running our current business and creating our future strategy. These principles include:

- talented employees;
- focus;
- balance of exploration and acquisitions;
- emphasis on technology and teamwork;
- mindset of an independent;
- control of operations; and
- employee ownership.

Our Business Strategy

Our mission is to create long-term stockholder value by safely, ethically and profitably exploring for, acquiring and developing oil and natural gas resources. Our business strategy has led us into unconventional resource plays that have lengthened our reserve life. Today we have a diversified asset portfolio capable of sustainable growth. Our core strategy consists of the following key elements:

- maintaining a diversified portfolio of core assets;
- maintaining a strong capital structure;
- growing through a combination of development drilling and select acquisitions;
- operating our assets and improving operational efficiencies; and
- attracting and retaining quality employees and ensuring their interests are aligned with our stockholders' interests.

Maintaining a Diversified Portfolio of Core Assets. Over the last several years, we have diversified our portfolio of assets and therefore our exposure to the unique risks our industry faces, such as geologic, geographic and commodity price risks (crude oil and natural gas). We believe that our diverse asset portfolio helps us mitigate these risks and provides us with the flexibility to respond quickly to the volatility in the oil and gas industry. In line with this element of our strategy, our 2012 plans include:

- Focusing on our oil and liquids-rich assets that today provide higher returns due to weak natural gas prices;
- Growing oil and liquids-rich production to more than 50% of our total production;
- Allocating substantially all of our planned \$1.5 to \$1.7 billion capital investments to our oil and liquids-rich assets; and
- Limiting investments in natural gas, accepting natural field declines in our gas assets and preserving future opportunities in our major held-by-production natural gas assets.

Maintaining a Strong Capital Structure. We believe that maintaining a strong capital structure is central to our strategy. A strong balance sheet preserves financial flexibility and helps ensure that we maintain sufficient liquidity to implement our overall business strategy. In line with this element of our strategy, our 2012 plans include:

- Living within our internal resources, including cash flows from operations, proceeds from non-strategic asset sales and, if needed, the use of our credit facility;
- Continuing to monetize non-strategic assets and using the proceeds to develop oil and liquids-rich plays and manage our leverage ratios; and
- Using derivative markets, when attractive, to hedge a portion of our future production to manage commodity price risk and to help ensure adequate funds to execute our drilling programs.

Growing Through a Combination of Development Drilling and Select Acquisitions. Throughout our history, our growth has come from a combination of select acquisitions and exploration and exploitation drilling. We develop resources in our focus areas while continually looking for new opportunities in and around these areas. To manage risks associated with our strategy to grow reserves through drilling, substantially all of the wells we drilled in 2011 were lower-risk with low to moderate reserve potential. Since 2000, we have completed six significant acquisitions that led to the expansion of our operating areas or the establishment of new focus areas onshore in the United States. Our most recent acquisition was the 2011 acquisition of approximately 65,000 net acres in the Uinta Basin. We also have recently assembled a 125,000 net-acre position in the Anadarko Basin's prolific Cana Woodford play in Oklahoma. Both of these transactions fit well with our existing properties and are in areas where our core competencies are applicable. In line with this element of our strategy, our 2012 plans include:

- Focusing on developing domestic, unconventional resource plays of scale;
- Delivering more than 20% oil and liquids growth by focusing on developing our fields in the Uinta and Williston basins and offshore Malaysia;
- Assessing and developing our oil and liquids-rich Cana Woodford play in the Anadarko Basin; and
- Continuing to consider select acquisition opportunities aligned with our strategy and asset base.

Operating our Assets and Improving Operational Efficiencies. We prefer to operate our properties. By controlling operations, we can better manage the timing of their development and production, control operating expenses and capital expenditures, ensure the appropriate application of technologies and promote safety and corporate responsibility. We operate a significant portion of our total net production and believe that improving operational efficiencies requires extensive knowledge of the geologic and operating conditions in the areas where we operate. Therefore, we focus our efforts on a limited number of geographic areas where our core competencies provide a competitive advantage and can positively influence operational efficiencies. Geographic focus also allows for the more efficient use of both our capital and human resources. In line with this element of our strategy, our 2012 plans include:

- Improving operational efficiencies by focusing on our unconventional resource plays that have vast acreage positions and deep inventories of lower-risk drilling locations — these plays lend themselves to efficiency gains in drilling and completion operations and provide sustainable growth profiles;

- Increasing corporate responsibility awareness and continuing to encourage all of our people to maintain safe operations, minimize environmental impact and conduct their daily business with the highest of ethical standards;
- Focusing on superlative execution; and
- Ensuring that the right people are deployed on the right projects.

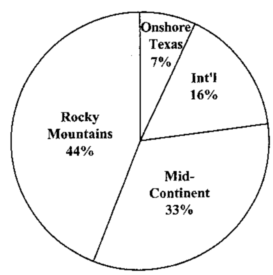
Attracting and Retaining Quality Employees and Ensuring Their Interests are Aligned with our Stockholders' Interests. "Employees" are represented in two of our founding business principles. We believe in hiring top-tier talent and are committed to their education and development. We believe that employees should be rewarded for their performance and that their interests should be aligned with our stockholders' interests. As a result, we reward and encourage our employees through performance-based compensation and equity ownership.

2012 Outlook and Capital Investments

Our 2012 capital budget is $1.5 to $1.7 billion, excluding acquisitions and approximately $210 million of capitalized interest and overhead. Substantially all of our capital investments will be allocated to oil or liquids-rich gas projects. The budget will be funded through our estimate of 2012 cash flows from operations, non-strategic assets sales and the use of our credit facility, as needed. Approximately $310 million in non-strategic asset sales have closed in the first quarter of 2012. We also plan to explore strategic options for our assets in the Gulf of Mexico.

Our oil and liquids production is expected to grow more than 20% in 2012. Conversely, our natural gas production will decrease as much as 15% in 2012 due to natural field declines and reduced investments. We expect our 2012 production to range from 290 – 300 Bcfe, or flat to slightly higher than our production in 2011.

Our estimated 2012 capital investments by area are shown below:



$1.5 - $1.7 Billion

Approximately 62% of our expected 2012 domestic natural gas and 95% of our domestic oil production is hedged. For a complete discussion of our hedging activities, a listing of open contracts as of December 31, 2011 and the estimated fair value of these contracts as of that date, see Note 4, "Derivative Financial Instruments," to our consolidated financial statements in Item 8 of this report.

Overview of Our Properties and Plans for 2012

Resource Plays

A key element of our 2012 strategy is to focus on domestic, unconventional resource plays of scale. These plays represent approximately 85% of our proved reserves and 94% of our probable reserves at year-end 2011. In 2012, we will focus on our oil and liquids-rich plays including the Uinta, Williston and Anadarko basins. We will also invest about 16% of our budget for the continued development of our offshore oil assets in Southeast Asia and China.

Rocky Mountains. As of December 31, 2011, we owned an interest in approximately 825,000 net acres in the Rocky Mountains area. Our assets are primarily oil and characterized by long-lived production. Our efforts today are focused primarily in the Uinta and Williston basins.

Uinta Basin. We are a major operator in the state of Utah, comprising approximately 30% of the state's total oil production. We have approximately 230,000 net acres in the Uinta Basin and our operations in the Basin can be divided into two areas: our legacy Monument Butte and our new position in the Central Basin, located immediately north and adjacent to Monument Butte.

We have approximately 1,800 productive oil wells in the Green River formation in our Monument Butte field. Until 2011, this field comprised substantially all of our production in the Basin. Our 2011 acquisition of acreage north of Monument Butte added approximately 65,000 net acres and new and deeper play types, including the Uteland Butte and Wasatch formations. At year-end 2011, we had drilled approximately 20 wells in these new plays with encouraging results.

Our net production from the Uinta Basin was approximately 22,000 BOEPD as of December 31, 2011. In 2012, we plan to have a large portion of our drilling activity occur in the Central Basin. We expect that at least four of our seven to eight operated rigs in the region will be drilling Uteland Butte and Wasatch targets. In addition, we intend to test multiple horizontal targets across this acreage. We estimate that we have more than 6,000 remaining drilling locations in the Uinta Basin, or more than three times the number of oil wells currently producing in our Monument Butte field.

Williston Basin. We have approximately 65,000 net acres under development on the Nesson Anticline of North Dakota and west of the Nesson. In addition, we have about 40,000 net acres in the mature Elm Coulee field, located in Richland County, Montana. To date, we have drilled 67 successful wells in North Dakota with production primarily from the Bakken formation. Our acreage is also prospective for the Sanish/Three Forks formation. Our net production was approximately 7,500 BOEPD as of December 31, 2011. We plan to run two to four operated rigs in the Williston Basin in 2012.

Southern Alberta Basin. We have approximately 340,000 net acres in the Southern Alberta Basin of northern Montana. Drilling conducted in 2010 and 2011 satisfied substantially all of our obligations on our initial five-year lease agreements for acreage in this area. Limited activity is planned in the Southern Alberta Basin in 2012.

Mid-Continent. Our traditional activities in the Mid-Continent have been focused largely on two natural gas plays – the Arkoma Woodford and the Granite Wash. With the weakness in natural gas prices, our capital investments in the region have shifted to our new oil and liquids-rich play in the Cana Woodford, located in the Anadarko Basin. As of December 31, 2011, we had approximately 480,000 net acres in the Mid-Continent and our production was approximately 330 MMcfe/d.

Woodford Shale. We have more than 300,000 net acres in Oklahoma's Woodford play. Approximately 170,000 net acres are in the Arkoma Woodford Basin. This play is primarily a dry gas shale formation that varies in thickness from 100 – 200 feet throughout our acreage. Our activity levels in the natural gas portion of the Woodford were reduced in 2011 due to low natural gas prices. Our net daily production in the Arkoma Woodford was approximately 180 MMcfe/d as of December 31, 2011. By choosing to limit investment in this play in 2012, we expect declines in natural gas production. Substantially all of our acreage is held-by-production in the Arkoma Woodford.

At year-end 2011, we had more than 125,000 net acres in the Cana Woodford play, located in the Anadarko Basin. The play is liquids-rich where the Woodford formation varies in thickness from 100 – 250 feet. An active assessment program is underway with the intent of running four to seven operated rigs in the area in 2012.

Granite Wash. We have approximately 50,000 net acres in the Granite Wash, located in Oklahoma and the Texas Panhandle. Our net production from the region was approximately 101 MMcfe/d as of December 31, 2011. Our largest producing field in the Granite Wash is Stiles/Britt Ranch, where we operate and own 17,000 net acres. During 2011, we ran three to four operated rigs in the Granite Wash. Due to low natural gas prices, we will limit our investment in this area in 2012.

Onshore Texas. We have approximately 317,000 net acres in the Eagle Ford and Pearsall shales in the Maverick Basin, located in Maverick, Dimmit and Zavala counties, Texas. To date, we have completed a total of 54 wells in the basin and our production was approximately 3,800 BOEPD as of December 31, 2011. The acreage includes multiple geologic horizons including the Georgetown, Glen Rose, Pearsall, Austin Chalk and the Eagle Ford.

Conventional Plays

We have operations in conventional plays onshore Texas, offshore Malaysia and China and in the Gulf of Mexico.

Onshore Texas. In 2011, we slowed our activities in many of our conventional natural gas plays and monetized certain non-strategic assets. As of December 31, 2011, we owned an interest in approximately 147,000 net acres in conventional onshore Texas plays with net production of approximately 88 MMcfe/d. With the outlook of continued low natural gas prices, we plan low levels of investment in these plays during 2012, and expect production from this area to decline.

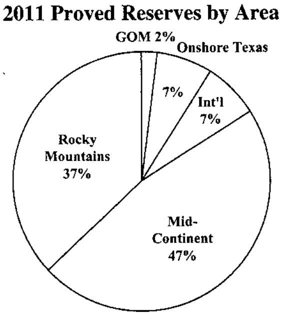
International. Our international activities are focused on offshore oil developments in Southeast Asia and China. We have production and active developments offshore Malaysia and China. As of February 21, 2012, our net production from Malaysia was at a record 29,000 BOPD. We have an interest in approximately 925,000 net acres offshore Malaysia and approximately 290,000 net acres offshore China. In 2012, our plans include continued development of our oil fields offshore Malaysia and approximately a $100 million investment in our Pearl field in the Pearl River Mouth Basin of China. First production from our Pearl field is expected in late 2013 or early 2014. We expect our international production to grow more than 25% year-over-year in 2012.

Gulf of Mexico. As of December 31, 2011, we owned interests in 91 deepwater leases and approximately 275,000 net acres. Our net production from the Gulf of Mexico was approximately 75 MMcfe/d as of December 31, 2011. In February 2012, production commenced from our deepwater Pyrenees development, with net daily production of approximately 3,300 BOEPD. With our continued emphasis on oil growth and domestic focus on developing long-lived onshore resource plays, we now consider our Gulf of Mexico assets to be "non-strategic." As a result, we are not planning to drill any additional exploratory wells in the Gulf of Mexico and are exploring options in 2012 to realize the value of these assets.

Reserves

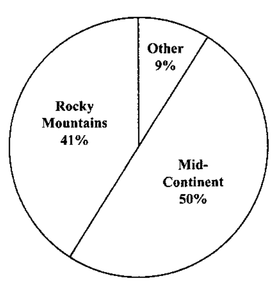
At year-end 2011, we had proved reserves of 3.9 Tcfe, a 5% increase over proved reserves at year-end 2010. At the end of 2011, our proved reserves were 60% natural gas and 54% proved developed. Our probable reserves were 65% natural gas. Our year-end 2011 proved reserve life index was approximately 13 years. Our 2011 production was 300 Bcfe.

2011 Proved Reserves by Area



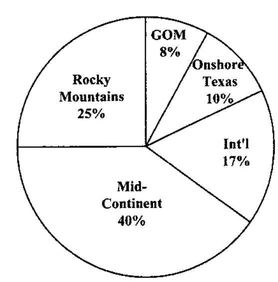
3.9 Tcfe

2011 Probable Reserves by Area



2.6 Tcfe

2012 Estimated Production by Area



290-300 Bcfe

Concentration

Reserves Concentration. The table below sets forth the concentration of our proved and probable reserves by location and the percentage of those reserves attributable to our largest fields. Our largest fields, the Woodford Shale and Monument Butte, accounted for about 45% of the total net present value of our proved reserves at December 31, 2011.

	Percentage of Proved Reserves	Percentage of Probable Reserves
Located domestically	93	97
Located onshore	91	96
10 largest fields	88	97
2 largest fields	63	68

Largest Fields. The table below sets forth for our largest fields (those whose reserves are greater than 10% of our total proved reserves), including Monument Butte and the Woodford Shale, the annual production volumes, average realized prices and related production cost structure on a per unit of production basis. For a discussion regarding our total domestic and international annual production volumes, average realized prices and related production cost structure on a per unit of production basis, see Item 7, *"Management's Discussion and Analysis of Financial Condition and Results of Operations* — Results of Operations."

	Year Ended December 31,		
	2011	2010	2009
Production:			
Natural gas (Bcf)			
Monument Butte(1)	6.4	4.8	3.9
Woodford Shale	69.4	76.2	61.1
Oil, condensate and NGLs (MBbls)			
Monument Butte	4,799	4,811	4,182
Woodford Shale	217	168	86
Average Realized Prices:			
Natural gas (per Mcf)			
Monument Butte	$ 3.52	$ 3.24	$ 2.18
Woodford Shale	$ 3.57	$ 3.86	$ 3.17
Oil, condensate and NGLs (per Bbl)			
Monument Butte	$78.00	$65.00	$48.02
Woodford Shale	$60.96	$46.81	$48.44
Production Cost:			
Monument Butte (per BOE)	$13.04	$ 8.91	$ 7.65
Woodford Shale (per Mcfe)	$ 1.03	$ 0.94	$ 0.82

(1) Does not include production from the Central Basin or other acreage that we own in the Uinta Basin.

Estimated Reserves

All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. The preparation of our oil and gas reserves estimates is completed in accordance with our prescribed internal control procedures, which include verification of data input into reserves forecasting and economics evaluation software, as well as multi-discipline management reviews, as described below. The technical employee responsible for overseeing the preparation of the reserves estimates has a Bachelor of Science in Petroleum Engineering, with more than 30 years of experience (including 20 years of experience in reserve estimation).

Our reserves estimates are made using available geological and reservoir data as well as production performance data. These estimates, made by our petroleum engineering staff, are reviewed annually with management and revised, either upward or downward, as warranted by additional data. The data reviewed includes, among other things, seismic data, well logs, production tests, reservoir pressures, individual well and field performance data. The data incorporated into our interpretations includes structure and isopach maps, individual well and field performance and other engineering and geological work products such as material balance calculations and reservoir simulation to arrive at conclusions about individual well and field projections. Additionally, offset performance data, operating expenses, capital costs and product prices factor into estimating quantities of reserves. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions and governmental regulations, as well as changes in the expected recovery rates associated with infill drilling. Sustained decreases in prices, for example, may cause a reduction in some reserves due to reaching economic limits sooner.

Actual quantities of reserves recovered will most likely vary from the estimates set forth below. Reserves and cash flow estimates rely on interpretations of data and require assumptions that may be inaccurate. For a discussion of these interpretations and assumptions, see *"Actual quantities of oil and gas reserves and future cash flows from those reserves will most likely vary from our estimates"* under Item 1A of this report. Our estimates of proved reserves, proved developed reserves and proved undeveloped reserves and future net cash flows and discounted future net cash flows from proved reserves at December 31, 2011, 2010 and 2009 and changes in proved reserves during the last three years are contained in "Supplementary Financial Information — Supplementary Oil and Gas Disclosures" in Item 8 of this report.

The following table shows, by country and in the aggregate a summary of our proved and probable oil and gas reserves as of December 31, 2011.

	Oil, Condensate and NGLs	Natural Gas	Total
	(MMBbls)	(Bcf)	(Bcfe)(1)
Proved Developed Reserves:			
Domestic	98	1,405	1,989
International:			
Malaysia	17	4	109
China	5	—	31
Total International	22	4	140
Total Proved Developed	120	1,409	2,129
Proved Undeveloped Reserves:			
Domestic	122	924	1,659
International:			
Malaysia	6	—	36
China	15	—	87
Total International	21	—	123
Total Proved Undeveloped	143	924	1,782
Total Proved Reserves	263	2,333	3,911
Probable Developed Reserves:			
Domestic	—	14	17
International:			
Malaysia	1	—	5
China	—	—	—
Total International	1	—	5
Total Probable Developed	1	14	22
Probable Undeveloped Reserves:			
Domestic	144	1,594	2,455
International:			
Malaysia	3	46	63
China	3	—	21
Total International	6	46	84
Total Probable Undeveloped	150	1,640	2,539
Total Probable Reserves	151	1,654	2,561

(1) Billion cubic feet equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or NGLs.

Proved Reserves. Our year-end 2011 proved reserves of 3,911 Bcfe increased 5% as compared to our proved reserves at year-end 2010. Our reserves consisted of 1,849 Bcfe proved developed producing, 280 Bcfe proved developed non-producing and 1,782 Bcfe proved undeveloped reserves. Our proved crude oil and condensate reserves at year-end 2011 were 263 million barrels, compared to 204 million barrels at year-end 2010, an increase of 29%.

At December 31, 2010, our estimated proved undeveloped reserves were 1,548 Bcfe. During 2011, we spent $1.0 billion of drilling, completion and facilities-related capital to convert 327 Bcfe of our December 31, 2010 proved undeveloped reserves into proved developed reserves. During 2011, we added 572 Bcfe of new proved undeveloped reserves through drilling activities. Proved undeveloped reserve quantities are limited by the activity level of development drilling we expect to undertake during the 2012-2016 five-year period. Due to the higher returns on investment for oil over natural gas investments, we have continued to focus on oil projects in our portfolio. As a result, we reclassified approximately 87 Bcfe of proved undeveloped reserves (primarily Rocky Mountains natural gas reserves) to probable reserves because the slower pace of development activity placed them beyond the five-year development horizon. Quantities of reserves that would otherwise meet the definition of proved undeveloped reserves, except for the fact that they will be developed beyond the 2012-2016 five-year horizon (1,070 Bcfe), are classified as probable reserves, in accordance with SEC regulations. As a result of the foregoing and the performance-related revisions, our proved undeveloped reserves at December 31, 2011 were 1,782 Bcfe, 100% of which have been included in our reserve report for less than five years. In accordance with our focus on oil projects, our proved undeveloped oil reserves increased from 94 million barrels at year-end 2010 to 143 million barrels at year-end 2011, an increase of 52%. For additional information regarding the changes in our proved reserves, see our Supplementary Oil and Gas Disclosures under Item 8 of this report.

In the years 2009-2011, we developed 11%, 13% and 19%, respectively, of our prior year-end proved undeveloped reserves. The development plans in our year-end reserve report reflect (i) the allocation of capital to projects in the first year of activity based upon the initial budget for such year and (ii) in subsequent years, the capital allocation in our five-year business plan, each of which generally is governed by our expectations for capital investment in such time period. Changes in commodity pricing between the time of preparation of the reserve report and actual investment, investment alternatives that may have been added to our portfolio of assets, changes in the availability and costs of oilfield services, and other economic factors may lead to changes in our development plans. As a result, the future rate at which we develop our proved undeveloped reserves may vary from historical development rates.

Probable Reserves. Our total estimated probable reserves of 2,561 Bcfe at December 31, 2011, consisted of 22 Bcfe of developed and 2,539 Bcfe of undeveloped reserves, as compared to probable developed and undeveloped reserves at year-end 2010 of 34 Bcfe and 2,439 Bcfe, respectively. Our probable crude oil and condensate reserves at year-end 2011 were 151 million barrels, compared to 106 million barrels at year-end 2010, an increase of 43%.

At December 31, 2010, our estimated probable reserves were 2,473 Bcfe. During 2011, we converted 408 Bcfe of our December 31, 2010 probable reserves into proved developed reserves. During 2011, we added probable reserves of 952 Bcfe through our exploration, development and acquisition activities. Probable reserves were reduced for (i) price related revisions and conversions to contingent probable reserves (256 Bcfe), (ii) sales of properties (71 Bcfe) and (iii) changes in well design and/or configuration (131 Bcfe). As a result of the foregoing and other revisions, our probable reserves at December 31, 2011 were 2,561 Bcfe.

Probable undeveloped reserves of 2,539 Bcfe at year-end 2011 include 1,070 Bcfe that would otherwise meet the definition of proved undeveloped reserves, except that they will not be developed during the 2012-2016 five-year horizon. The characteristic uncertainties associated with the remaining 1,469 Bcfe of undeveloped probable reserves vary significantly between our major operating areas. These uncertainties restrain this reserve classification from becoming proved reserves due to their cumulative effect on achieving the reasonable certainty threshold required for proved reserves. These additional uncertainties include the lack of 3-D seismic control, uncertainty associated with geologic and reservoir continuity with increasing distance away from a producing well, immature portions of an existing waterflood, secondary response in areas of a field that has exhibited lower primary waterflood recoveries, incremental recovery factors and field development timing associated with regulatory and/or governmental approval.

Reserves Sensitivities

To determine our year-end 2011 reserves estimates, we utilized the unweighted average first-day-of-the-month natural gas and crude oil prices for the prior twelve months, which was $4.12 per MMBtu and $96.13 per barrel, respectively, adjusted for market differentials.

The quantity of our proved reserves decreases slightly at lower crude oil prices as a result of shortening the economic life of our proved developed reserves. Our development plans would not materially change across a range of crude oil prices between $60 and $90 per barrel and, therefore, have little impact on the quantity of proved undeveloped reserves. That quantity is limited by the level of development drilling we expect to undertake during the 2012-2016 five-year period. Our proved undeveloped oil reserves are primarily in the Uinta and Williston basins.

At natural gas prices of $3.50 and $3.00, the quantity of our proved reserves would decrease by 1% and 13%, respectively. This decrease is mainly due to uneconomic proved undeveloped reserves in natural gas fields at lower natural gas prices.

Under the terms of our production sharing contracts in Malaysia and China, an increase or decrease in realized oil prices would result in a decrease or increase, respectively, in our proved reserves. At higher oil prices, lesser quantities of oil are required for cost recovery and at lower oil prices, greater quantities of oil are required for cost recovery. Our share (the contractor's share) of future production is impacted accordingly. The effect of higher or lower oil prices may be partially offset by extending or shortening, respectively, the economic life of proved reserves.

Drilling Activity

The following table sets forth the number of oil and gas wells that completed drilling for each of the last three years.

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Domestic:						
Productive(1)	263	159.2	360	215.6	273	153.1
Nonproductive(2)	2	1.0	6	3.0	8	4.8
International:						
China:						
Productive(3)	—	—	—	—	1	1.0
Nonproductive(4)	1	1.0	2	2.0	—	—
Malaysia:						
Productive(5)	1	0.7	1	0.4	1	0.4
Nonproductive(6)	—	—	3	2.6	—	—
International Total:						
Productive	1	0.7	1	0.4	2	1.4
Nonproductive	1	1.0	5	4.6	—	—
Exploratory well total	267	161.9	372	223.6	283	159.3
Development wells:						
Domestic:						
Productive	253	199.6	243	189.8	128	98.7
International:						
China:						
Productive	—	—	5	0.6	12	1.4
Malaysia:						
Productive	17	5.8	7	4.3	5	2.8
Nonproductive	—	—	1	0.6	—	—
International Total:						
Productive	17	5.8	12	4.9	17	4.2
Nonproductive	—	—	1	0.6	—	—
Development well total	270	205.4	256	195.3	145	102.9

(1) Includes 61 gross (37.6 net), 126 gross (91.1 net) and 29 gross (17.7 net) wells in 2011, 2010 and 2009, respectively, that are not exploitation wells.

(2) Includes 6 gross (3.0 net) and 3 gross (1.3 net) wells in 2010 and 2009, respectively, that are not exploitation wells.

(3) Includes 1 gross (1.0 net) well in 2009 that is not an exploitation well.

(4) Includes 1 gross (1.0 net) and 2 gross (2.0 net) wells in 2011 and 2010, respectively, that are not exploitation wells.

(5) Includes 1 gross (0.7 net), 1 gross (0.4 net) and 1 gross (0.4 net) wells in 2011, 2010 and 2009, respectively, that are not exploitation wells.

(6) Includes 2 gross (2.0 net) wells in 2010 that are not exploitation wells.

We were in the process of drilling 16 gross (9.6 net) exploitation wells and 24 gross (19.7 net) development wells domestically at December 31, 2011. Internationally, we were drilling 1 gross (0.6 net) exploratory well in Malaysia at December 31, 2011.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned an interest as of December 31, 2011 and the location of, and other information with respect to, those wells. As of December 31, 2011, we had 8 gross (2.5 net) oil wells with multiple completions.

	Company Operated Wells		Outside Operated Wells		Total Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
Domestic:						
Offshore:						
Oil	1	0.6	2	0.5	3	1.1
Natural gas	6	3.9	3	0.9	9	4.8
Onshore:						
Oil	2,375	1,926.9	830	73.9	3,205	2,000.8
Natural gas	1,457	1,163.6	1,098	212.9	2,555	1,376.5
Total Domestic:						
Oil	2,376	1,927.5	832	74.4	3,208	2,001.9
Natural gas	1,463	1,167.5	1,101	213.8	2,564	1,381.3
International:						
Offshore China:						
Oil	—	—	46	5.5	46	5.5
Offshore Malaysia:						
Oil	25	15.4	23	11.5	48	26.9
Natural gas	—	—	1	0.5	1	0.5
Total International:						
Oil	25	15.4	69	17.0	94	32.4
Natural gas	—	—	1	0.5	1	0.5
Total:						
Oil	2,401	1,942.9	901	91.4	3,302	2,034.3
Natural gas	1,463	1,167.5	1,102	214.3	2,565	1,381.8
Total	3,864	3,110.4	2,003	305.7	5,867	3,416.1

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements or production sharing contracts. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. Generally, an operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

Acreage Data

As of December 31, 2011, we owned interests in developed and undeveloped oil and gas acreage set forth in the table below. Domestic ownership interests generally take the form of "working interests" in oil and gas leases that have varying terms. International ownership interests generally arise from participation in production sharing contracts.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
	(In thousands)			
Domestic:				
Offshore	59	28	388	247
Onshore:				
Mid-Continent	627	338	537	143
Rocky Mountains	274	177	881	647
Gulf Coast	582	457	162	110
Appalachia	—	—	74	37
Total Onshore	1,483	972	1,654	937
Total Domestic	1,542	1,000	2,042	1,184
International:				
Offshore China	22	3	287	287
Offshore Malaysia	201	104	2,256	819
Total International	223	107	2,543	1,106
Total	1,765	1,107	4,585	2,290

The table below summarizes by year and geographic area our undeveloped acreage scheduled to expire in the next five years. In most cases, the drilling of a commercial well, or the filing and approval of a development plan or suspension of operations, will hold acreage beyond the expiration date. We own fee mineral interests in 439,804 gross (105,431 net) undeveloped acres. These interests do not expire.

	Undeveloped Acres Expiring									
	2012		2013		2014		2015		2016	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(In thousands)									
Domestic:										
Offshore	—	—	44	17	86	72	35	22	52	29
Onshore:										
Mid-Continent	37	18	61	31	261	73	92	13	66	7
Rocky Mountains	54	35	57	24	72	49	112	66	73	35
Gulf Coast	30	17	29	18	19	13	1	—	—	—
Total Onshore	121	70	147	73	352	135	205	79	139	42
Total Domestic	121	70	191	90	438	207	240	101	191	71
International:										
Offshore China	—	—	275	275	—	—	—	—	—	—
Offshore Malaysia	—	—	1,177	388	1,079	431	—	—	—	—
Total International	—	—	1,452	663	1,079	431	—	—	—	—
Total	121	70	1,643	753	1,517	638	240	101	191	71

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, ordinary course liens incidental to operating agreements and for current taxes, development obligations under oil and gas leases or capital commitments under production sharing contracts or exploration licenses. As is customary in the industry in the case of undeveloped properties, often little investigation of record title is made at the time of acquisition. Investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

Marketing

Substantially all of our oil and gas production is sold to a variety of purchasers under short-term contracts (less than 12 months) and, most recently, long-term contracts in the Uinta Basin, at market sensitive prices. For a list of purchasers of our oil and gas production that accounted for 10% or more of our consolidated revenue for the three preceding calendar years, please see Note 1, "Organization and Summary of Significant Accounting Policies — *Major Customers,*" to our consolidated financial statements in Item 8 of this report, which information is incorporated herein by reference. We believe that the loss of any of these purchasers would not have a material adverse effect on us because alternative purchasers are readily available with the exception of purchasers of our Uinta Basin oil production.

Due to the higher paraffin content of our Uinta Basin production, there is limited refining capacity for it outside of the Salt Lake City area. In late 2011 and early 2012, we signed two separate long-term agreements (7 and 10 years, respectively) for 38,000 BOPD of refining capacity in the Uinta Basin. In December 2011, we executed a crude oil supply agreement with Tesoro Corporation to provide 18,000 barrels per day of supply capacity at Tesoro's refinery in Salt Lake City, Utah. This agreement spans a seven-year period with commitments commencing in 2013. In January 2012, we executed a crude oil supply agreement with HollyFrontier Corporation to provide 20,000 barrels per day of supply capacity at HollyFrontier's Woods Cross, Utah refinery. This agreement spans a ten-year period with commitments commencing in 2014. We continue to seek additional capacity to accommodate our growth plans for the Uinta Basin. Please see the discussion under *"There is limited transportation and refining capacity for our black and yellow wax crude oil, which may limit our ability to sell our current production or to increase our production in the Uinta Basin"* in Item 1A of this report.

Competition

Competition in the oil and gas industry is intense, particularly with respect to the hiring and retention of technical personnel, the acquisition of properties and access to drilling rigs and other services. For a further discussion, please see the discussion under *"Competition for experienced technical personnel may negatively impact our operations or financial results"* and *"Competition in the oil and gas industry is intense"* in Item 1A of this report, which information is incorporated herein by reference.

Employees

As of February 21, 2012, we had 1,643 employees. All but 157 of our employees were located in the United States. None of our employees are covered by a collective bargaining agreement. We believe that relationships with our employees are satisfactory.

Regulation

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, local and international regulations. An overview of these regulations is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Please see the discussion under the caption *"We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business,"* in Item 1A of this report.

General Overview. Our oil and gas operations are subject to various federal, state, provincial, tribal, local and international laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- acquisition of seismic data;
- location of wells;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and gas properties;
- drilling and casing of wells;
- issuance of permits in connection with exploration, drilling and production;
- well production;
- spill prevention plans;
- emissions permitting or limitations;
- protection of endangered species;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells; and
- transportation of production.

Federal Regulation of Drilling and Production. Many of our domestic oil and gas leases are granted by the federal government and administered by the BOEMRE or the BLM, both federal agencies. BOEMRE and BLM leases contain relatively standardized terms and require compliance with detailed BLM or BOEMRE regulations and, in the case of offshore leases, orders pursuant to the Outer Continental Shelf Lands Act, or OCSLA (which are subject to change by the BOEMRE). Many onshore leases contain stipulations limiting activities that may be conducted on the lease. Some stipulations are unique to particular geographic areas and may limit the time during which activities on the lease may be conducted, the manner in which certain activities may be conducted or, in some cases, may ban surface activity. For offshore operations, lessees must obtain BOEMRE approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies (such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency), lessees must obtain a permit from the BLM or the BOEMRE, as applicable, prior to the commencement of drilling, and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the Shelf and removal of facilities. To cover the various obligations of lessees on the Shelf, the BOEMRE generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of such bonds or other surety can be substantial and there is no assurance that bonds or other surety can be obtained in all cases. We are currently exempt from the supplemental bonding requirements of the BOEMRE. Under certain circumstances, the BLM or the BOEMRE, as applicable, may require that our operations on federal leases be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations.

The BOEMRE regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases provide that the BOEMRE will collect royalties based upon the market value of oil produced from federal leases. The 2005 EPA formalizes the royalty in-kind program of the BOEMRE, providing that the BOEMRE may take royalties in-kind if the Secretary of the Interior determines that the benefits are greater than or equal to the benefits that are likely to have been received had royalties been taken in value. We believe that the BOEMRE's royalty in-kind program will not have a material effect on our financial position, cash flows or results of operations.

In 2006, the BOEMRE amended its regulations to require additional filing fees. The BOEMRE has estimated that these additional filing fees will represent less than 0.1% of the revenues of companies with offshore operations in most cases. We do not believe that these additional filing fees will affect us in a way that materially differs from the way they affect other producers, gatherers and marketers with which we compete.

State and Local Regulation of Drilling and Production. We own interests in properties located onshore in a number of states and in state waters offshore Texas. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas. The effect of these regulations is to limit the amounts of oil and gas we can produce from our wells and to limit the number of wells or the locations at which we can drill.

Environmental Regulations. We are subject to various federal, state, provincial, tribal, local and international laws and regulations concerning occupational safety and health as well as the discharge of materials into, and the protection of, the environment. Environmental laws and regulations relate to, among other things:

- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials;
- the emission of certain gases into the atmosphere;
- the monitoring, abandonment, reclamation and remediation of well and other sites, including sites of former operations;
- various environmental permitting requirements; and
- the development of emergency response and spill contingency plans.

We consider the costs of environmental protection and safety and health compliance necessary and manageable parts of our business. We have been able to plan for and comply with environmental regulations without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and will likely continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters and the cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial and damage payment obligations, or the issuance of injunctive relief (including orders to cease operations). Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted. Moreover, some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts onshore or offshore drilling or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected.

The Oil Pollution Act, or OPA, imposes regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from spills in U.S. waters. A "responsible party" includes the owner or operator of an onshore facility, vessel or pipeline, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns strict, joint and several liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of such limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation, or if the party fails to report a spill or to cooperate fully in the cleanup. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75 million in other damages for offshore facilities and up to $350 million for onshore facilities. Few defenses exist to the liability imposed by OPA. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party to administrative, civil or criminal enforcement actions.

OPA also requires operators in the Gulf of Mexico to demonstrate to the BOEMRE that they possess available financial resources that are sufficient to pay for costs that may be incurred in responding to an oil spill. Under OPA and implementing BOEMRE regulations, responsible parties are required to demonstrate that they possess financial resources sufficient to pay for environmental cleanup and restoration costs of at least $10 million for an oil spill in state waters and at least $35 million for an oil spill in federal waters.

In addition to OPA, our discharges to waters of the U.S. are further limited by the federal Clean Water Act, or CWA, and analogous state laws. The CWA prohibits any discharge into waters of the United States except in compliance with permits issued by federal and state governmental agencies. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may also result in administrative, civil or criminal enforcement actions. The OPA and CWA also require the preparation of oil spill response plans and spill prevention, control and countermeasure or "SPCC" plans. We have such plans in place and have made changes as necessary due to changes by the U.S. Environmental Protection Agency, also known as the "EPA," and delays in EPA rulemaking. The final EPA rule was published in November 2009 and became effective on January 14, 2010, with a compliance deadline of November 2010.

The National Environmental Policy Act, or NEPA, requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. This regulation can lead to additional costs and delays in permitting for operators as they may need to apply to the BLM for additional Environmental Assessments and more detailed Environmental Impact Statements.

The Endangered Species Act restricts activities that may affect federally-identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal or permanent ban in affected areas. Similarly, the Migratory Bird Treaty Act, or MBTA, implements various treaties and conventions between the U.S. and certain other nations for the protection of migratory birds. Under the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal or permanent ban in affected areas.

OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the Shelf. Specific design and operational standards may apply to vessels, rigs, platforms, vehicles and structures operating or located on the Shelf. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial administrative, civil and criminal penalties, as well as potential court injunctions curtailing operations and the cancellation of leases.

The Resource Conservation and Recovery Act, or RCRA, generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy," the EPA and state agencies may regulate these wastes as solid wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on persons that are considered to have contributed to the release of a "hazardous substance" into the environment. Such "responsible persons" may be subject to joint and several liability under the Superfund law for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease onshore properties that have been used for the exploration and production of oil and gas for a number of years. Many of these onshore properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and any wastes that may have been disposed or released on them may be subject to the Superfund law, RCRA and analogous state laws and common law obligations, and we potentially could be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination.

The Clean Air Act, or CAA, and comparable state statutes restrict the emission of air pollutants and affects both onshore and offshore oil and gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the EPA has developed and continues to develop more stringent regulations governing emissions of toxic air pollutants, and is considering the regulation of additional air pollutants and air pollutant parameters. These regulations may increase the costs of compliance for some facilities.

The Occupational Safety and Health Act, or OSHA, and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Congress has been actively considering legislation to reduce emissions of greenhouse gases (GHG), primarily through the development of GHG cap and trade programs. In June of 2009, the U.S. House of Representatives passed a cap and trade bill known as the American Clean Energy and Security Act of 2009, which is now being considered by the U.S. Senate. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of GHG. Further, on April 2, 2007, the United States Supreme Court in Massachusetts, et al. v. the EPA, held that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act. On April 24, 2009, the EPA responded to the Massachusetts, et al. v. the EPA decision with a proposed finding that the current and projected concentrations of GHG in the atmosphere threaten the public health and welfare of current and future generations, and that certain GHG from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of GHG and hence to the threat of climate change. The EPA published the final version of this finding on December 15, 2009, which allowed the EPA to proceed with the rulemaking process to regulate GHG under the Clean Air Act. In anticipation of the finalization of the EPA's finding that GHG threaten public health and welfare, and that GHG from new motor vehicles contribute to climate change, the EPA proposed a rule in September of 2009 that would require a reduction in emissions of GHG from motor vehicles and would trigger applicability of Clean Air Act permitting requirements for certain stationary sources of GHG emissions. In response to this issue, the EPA also proposed a tailoring rule that would, in general, only impose GHG permitting requirements on facilities that emit more than 25,000 tons per year of GHG. Moreover, on September 22, 2009, the EPA finalized a rule requiring nation-wide reporting of GHG emissions in 2011 for emissions occurring in 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent GHG emissions per year, and to most upstream suppliers of fossil fuels and industrial GHG, as well as to manufacturers of vehicles and engines. Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Any additional costs or operating restrictions associated with legislation or regulations regarding GHG emissions could have a material adverse effect on our operating results and cash flows, in addition to the demand for the natural gas and other hydrocarbon products that we produce.

In addition, federal, state and local agencies are considering regulations, some of which have passed, related to hydraulic fracturing. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. The hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA and other federal regulatory agencies have taken steps to impose federal regulatory requirements. Certain states in which we operate, including Colorado, Pennsylvania, Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic fracturing process, and the RCT adopted rules regarding the same in December 2011. We currently voluntarily disclose all chemicals used in our hydraulic fracturing through FracFocus (http://fracfocus.org), the national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission, two organizations whose missions both revolve around conservation and environmental protection.

Federal Regulation of Sales and Transportation of Natural Gas. Our sales of natural gas are affected directly or indirectly by the availability, terms and cost of natural gas transportation. The prices and terms for access to pipeline transportation of natural gas are subject to extensive federal and state regulation. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or NGA, and by regulations and orders promulgated under the NGA by the FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations. The OCSLA requires that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its Natural Gas Act jurisdiction. Therefore, we do not believe that any FERC or BOEMRE action taken under OCSLA will affect us in a way that materially differs from the way it will affect other natural gas producers, gatherers and marketers with which we compete.

Pursuant to authority enacted in the Energy Policy Act of 2005, or 2005 EPA, FERC has promulgated anti-manipulation regulations, violations of which make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC to use or employ any device, scheme, or artifice to defraud, to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or to engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity. Violation of this requirement, similar to violations of other NGA and FERC requirements, may be penalized by the FERC up to $1 million per day per violation. FERC may also order disgorgement of profit and corrective action. We believe, however, that neither the 2005 EPA nor the regulations promulgated by FERC as a result of the 2005 EPA will affect us in a way that materially differs from the way they affect other natural gas producers, gatherers and marketers with which we compete.

Our sales of natural gas and oil are also subject to requirements under the Commodity Exchange Act, or CEA, and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

The current statutory and regulatory framework governing interstate natural gas transactions is subject to change in the future, and the nature of such changes is impossible to predict. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, the CFTC and the courts. The natural gas industry historically has been very heavily regulated. In the past, the federal government regulated the prices at which natural gas could be sold. Congress removed all price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. There is always some risk, however, that Congress may reenact price controls in the future. Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action the FERC will take. Therefore, there is no assurance that the current regulatory approach recently pursued by the FERC and Congress will continue. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Federal Regulation of Sales and Transportation of Crude Oil. Our sales of crude oil and condensate are currently not regulated. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other crude oil and condensate producers.

International Regulations. Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above imposed by the respective governments of the countries in which we operate, and may affect our operations and costs within that country. We currently have operations in Malaysia and China.

Financial Information

Financial information regarding the geographic areas in which we operate is incorporated herein by reference to Part II, Item 7, *"Management's Discussion and Analysis of Financial Condition and Results of Operations"* and Item 8, *"Financial Statements and Supplementally Information."*

Commonly Used Oil and Gas Terms

Below are explanations of some commonly used terms in the oil and gas business.

Basis risk. The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular hedging transaction.

Barrel or Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

BLM. The Bureau of Land Management of the United States Department of the Interior.

BOE. One barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

BOEMRE. Bureau of Ocean Energy Management, Regulation and Enforcement of the U.S. Department of the Interior, formally known as the Minerals Management Service (MMS).

BOEPD. Barrels of oil equivalent per day.

BOPD. Barrels of oil per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Deepwater. Generally considered to be water depths in excess of 1,000 feet.

Developed acres. The number of acres that are allocated or assignable to producing wells or wells capable of production.

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

DOI. United States Department of Interior.

Exploitation well. An exploration well drilled to find and produce probable reserves. Most of the exploitation wells we drill are located in the Mid-Continent or the Monument Butte field. Exploitation wells in those areas have less risk and less reserve potential and typically may be drilled at a lower cost than other exploration wells. For internal reporting and budgeting purposes, we combine exploitation and development activities.

Exploration well. An exploration well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

FERC. The Federal Energy Regulatory Commission.

FPSO. A floating production, storage and off-loading vessel commonly used overseas to produce oil from locations where pipeline infrastructure is not available.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Gross acres or gross wells. The total acres or wells in which we own a working interest.

Infill drilling or infill well. A well drilled between known producing wells to improve oil and gas reserve recovery efficiency.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

MMcfe/d. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate, produced per day.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million Btus.

MMMBtu. One billion Btus.

Net acres or net wells. The sum of the fractional working interests we own in gross acres or gross wells, as the case may be.

NYMEX. The New York Mercantile Exchange.

NYMEX Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the New York Mercantile Exchange. It is frequently referred to as the Henry Hub Index.

Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. The SEC provides a complete definition of probable reserves in Rule 4-10(a)(18) of Regulation S-X.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed reserves. In general, proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

Proved reserves. Proved 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.

Proved undeveloped reserves. In general, proved reserves 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. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

Reserve life index. This index is calculated by dividing total proved reserves at year-end by annual production to estimate the number of years of remaining production.

Shelf. The U.S. Outer Continental Shelf of the Gulf of Mexico. Water depths generally range from 50 feet to 1,000 feet.

Tcfe. One trillion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

Unconventional "resource" plays. Plays targeting tight sand, coal bed or gas shale reservoirs. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require horizontal drilling and stimulation treatments or other special recovery processes in order to produce economically.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Item 1A. ***Risk Factors***

There are many factors that may affect Newfield's business and results of operations. You should carefully consider, in addition to the other information contained in this report, the risks described below.

Oil and gas prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse impact on our business. Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas. Lower prices may reduce the amount of oil and gas that we can economically produce. Oil and gas prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital.

Among the factors that can cause fluctuations in oil and gas prices are:

- the domestic and foreign supply of oil, natural gas and natural gas liquids;
- the price and availability of, and demand for, alternative fuels;
- weather conditions and climate change;
- changes in supply and demand;
- world-wide economic conditions;
- the price of foreign imports;
- the availability, proximity and capacity of transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;
- political conditions in oil and gas producing regions; and
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental regulation.

We have substantial capital requirements to fund our business plans, and a continued slow recovery of the economy and the financial markets in 2012 or another decline or crisis as was experienced in late 2008 and 2009 could negatively impact our ability to execute our business plan. Although we anticipate that our 2012 capital spending, excluding acquisitions, will correspond with internally generated sources of cash (cash flows from operations, continued non-strategic asset sales and the use of our credit facility as needed), we may borrow and repay funds under our credit arrangements throughout the year since the timing of expenditures and the receipt of cash flows from operations do not necessarily match. Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We may have to reduce capital expenditures, and our ability to execute our business plans could be adversely affected, if:

- one or more of the lenders under our existing credit arrangements fail to honor its contractual obligation to lend to us;
- the amount that we are allowed to borrow under our existing credit facility is reduced; or
- our customers or working interest owners default on their obligations to us.

To maintain and grow our production and cash flows, we must continue to develop existing reserves and locate or acquire new reserves. Through our drilling programs and the acquisition of properties, we strive to maintain and grow our production and cash flow. However, as we produce from our properties, our reserves decline. We may be unable to find, develop or acquire additional reserves or production at an acceptable cost, if at all. In addition, these activities require substantial capital expenditures.

Actual quantities of oil and gas reserves and future cash flows from those reserves will most likely vary from our estimates. Estimating accumulations of oil and gas is complex. The process relies on interpretations of available geologic, geophysic, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires a number of economic assumptions, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

The proved and probable reserve information set forth in this report is based on estimates we prepared. Estimates prepared by others might differ materially from our estimates.

Actual quantities of oil and gas reserves, future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses will most likely vary from our estimates, with the variability likely to be higher for probable reserves estimates. In addition, the methodologies and evaluation techniques that we use, which include the use of multiple technologies, data sources and interpretation methods, may be different than those used by our competitors. Further, reserve estimates are subject to the evaluator's criteria and judgment and show important variability, particularly in the early stages of an oil and gas development. Any significant variance could materially affect the quantities and net present value of our reserves. In addition, we may adjust estimates of reserves to reflect production history, results of exploration and development activities and prevailing oil and gas prices. Our reserves also may be susceptible to drainage by operators on adjacent properties.

You should not assume that the present value of future net cash flows is the current market value of our proved oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials, and costs in effect at year-end. Actual future prices and costs may be materially higher or lower than the prices and costs we used. In addition, actual production rates for future periods may vary significantly from the rates assumed in the calculation.

Our use of oil and gas price hedging contracts may limit future revenues from price increases and involves the risk that our counterparties may be unable to satisfy their obligations to us. We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months as part of our risk management program. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. Reducing our exposure to price volatility is intended to help ensure that we have adequate funds available for our capital programs and to help us manage returns on some of our acquisitions and more price sensitive drilling programs. Although the use of hedging transactions limits the downside risk of price declines, it also may limit the benefit from price increases and expose us to the risk of financial loss in certain circumstances. Those circumstances include instances where our production is less than the hedged volume or there is a widening of price basis differentials between delivery points for our production and the delivery points assumed in the hedge transaction.

Hedging transactions also involve the risk that counterparties, which generally are financial institutions, may be unable to satisfy their obligations to us. Although we have entered into hedging contracts with multiple counterparties to mitigate our exposure to any individual counterparty, if any of our counterparties were to default on its obligations to us under the hedging contracts or seek bankruptcy protection, it could have a material adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future production being subject to commodity price changes. In addition, in poor economic environments and tight financial markets, the risk of a counterparty default is heightened, and it is possible that fewer counterparties will participate in future hedging transactions, which could result in greater concentration of our exposure to any one counterparty or a larger percentage of our future production being subject to commodity price changes.

Federal legislation regarding derivatives could have an adverse effect on our ability and cost of entering into derivative transactions. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Reform Act), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation requires the CFTC and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. On October 1, 2010, the CFTC introduced its first series of proposed rules coming out of the Dodd-Frank Reform Act. In July 2011, the CFTC granted temporary exemptive relief from certain swap regulation provisions of the legislation until December 31, 2011, or until the agency finalized the corresponding rules. In December 2011, the CFTC extended the potential latest expiration date of the exemptive relief to July 16, 2012. In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions are exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize other regulations, including critical rulemaking on the definition of "swap", "swap dealer" and "major swap participant." Depending on our classification under the regulations, the financial reform legislation may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities. The financial reform legislation may also require our counterparties to the derivative contracts to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, and increase our potential exposure to less creditworthy counterparties. If we reduce our use of derivatives or commodity prices decline as a result of the legislation and regulations, our results of operations may become more volatile and cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures, our results of operations, or our cash flows.

Drilling is a high-risk activity. In addition to the numerous operating risks described in more detail below, the drilling of wells involves the risk that no commercially productive oil or gas reservoirs will be encountered. In addition, we often are uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- costs of, or shortages or delays in the availability of, drilling rigs, equipment and materials;
- adverse weather conditions and changes in weather patterns;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- embedded oilfield drilling and service tools;
- equipment failures or accidents;
- lack of necessary services or qualified personnel;
- availability and timely issuance of required governmental permits and licenses;
- availability, costs and terms of contractual arrangements, such as leases, pipelines and related facilities to gather, process and compress, transport and market natural gas, crude oil and related commodities; and
- compliance with, or changes in, environmental, tax and other laws and regulations.

We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business. Existing and potential regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include:

- the amounts and types of substances and materials that may be released into the environment;
- response to unexpected releases to the environment;
- reports and permits concerning exploration, drilling, production and other operations;
- the spacing of wells;
- unitization and pooling of properties;
- calculating royalties on oil and gas produced under federal and state leases; and
- taxation.

Under these laws, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs, natural resource damages and other environmental damages. We also could be required to install expensive pollution control measures or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as the imposition of corrective action orders. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition, results of operations or cash flows.

In addition, changes to existing regulations or the adoption of new regulations may unfavorably impact us, our suppliers or our customers. For example, governments around the world have become increasingly focused on climate change matters. In December 2009, the EPA issued a final rule that the current and projected concentrations of GHG in the atmosphere threaten the public health and welfare of current and future generations, and that certain GHG from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of GHG and hence to the threat of climate change. This finding allowed the EPA to proceed with the rulemaking process to regulate GHG under the Clean Air Act. The EPA has adopted two sets of rules regulating GHG emissions under the Clean Air Act, one of which requires a reduction in emissions of GHG from motor vehicles and the other of which regulates emissions of GHG from certain large stationary sources, effective January 2, 2011, which could require GHG emission controls for those sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as from certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities on an annual basis, beginning in 2012 for emissions occurring in 2011. The new regulations could impact certain facilities in which we have interests (legal, equitable, operated or non-operated) by increasing the regulatory reporting requirements.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHG, and almost one-half of the states have already taken legal measures to reduce emissions of GHG primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas that is produced.

Further, the U.S. Congress has previously proposed legislation that would directly impact our industry, covering areas such as emission reporting and reductions and the regulation of over-the-counter commodity hedging activities. Similarly, in response to the 2010 Macondo incident in the Gulf of Mexico, the U.S. Congress was considering a number of legislative proposals relating to the upstream oil and gas industry both onshore and offshore that could result in significant additional laws or regulations governing our operations in the United States, including a proposal to raise or eliminate the cap on liability for oil spill cleanups under the Oil Pollution Act of 1990.

These and other potential regulations, if introduced and passed in Congress, could increase our costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business, negatively impacting our financial condition, results of operations and cash flows. See also "— *The potential adoption of federal, state and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.*"

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Additional costs or operating restrictions associated with legislation or regulations could have a material adverse effect on our operating results and cash flows, in addition to the demand for the natural gas and other hydrocarbon products that we produce.

The potential adoption of federal, state and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells. Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on almost all of our U.S. onshore oil and natural gas properties, including our unconventional resource plays in the Woodford Shale of Oklahoma, the Granite Wash of Texas and Oklahoma, the Uinta Basin of Utah and the Eagle Ford and Pearsall shales of southwest Texas, which represented approximately 82% of our proved reserves and approximately 89% of our probable reserves at year-end 2011. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore.

As explained in more detail below, the hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA and other federal regulatory agencies have taken steps to impose federal regulatory requirements. For example, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress to regulate hydraulic fracturing, including the Fracturing Responsibility and Awareness of Chemicals Act, which would provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. However, policymakers in at least two states (Kansas and North Dakota) have expressed concerns through the filing or passage of concurrent resolutions about federal regulation of hydraulic fracturing in light of authority over hydraulic fracturing.

Certain states in which we operate, including Colorado, Pennsylvania, Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic fracturing process, and the RCT adopted rules regarding the same in December 2011. In the past three years, news reports indicate that 23 states have approved or considered additional legislative mandates or administrative rules on hydraulic fracturing. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

Notwithstanding state regulatory requirements relating to hydraulic fracturing, there are steps by federal governmental agencies that are either underway or are being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. In a November 18, 2011 report, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued 20 recommendations to federal agencies, states, and private entities that are intended to reduce the environmental impact and assure the safety of shale gas production. In addition, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Given the heightened awareness regarding the use of hydraulic fracturing, it is possible that regulatory agencies or private parties may suggest that hydraulic fracturing has caused groundwater contamination, whether or not such allegations are accurate. For example, on December 8, 2011, the EPA released a preliminary report indicating that hydraulic fracturing is responsible for groundwater contamination in Pavillion, Wyoming, although the EPA's draft report has been hotly criticized as ignoring certain facts and utilizing incorrect data. In addition, the EPA has alleged in an enforcement action against an operator in Texas that the operator contaminated local groundwater wells, although the RCT found after an evidentiary hearing that the operator was not responsible for the contamination. Thus, regulatory agencies or private parties alleging groundwater contamination linked to hydraulic fracturing could trigger defense costs in administrative or civil litigation to rebut the allegations.

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

Further, on July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically-fractured gas wells. These standards include the reduced emission completion (REC) techniques developed in the EPA's Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently researching the effect these proposed rules could have on our business. Final action on the proposed rules is expected no later than April 3, 2012.

Based on the foregoing, increased regulation and attention given to the hydraulic fracturing process from federal agencies, various states and local governments could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation. On September 12, 2011, President Obama sent to Congress a legislative package that includes proposed legislation that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, among other proposals:

- the repeal of the percentage depletion allowance for oil and natural gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain domestic production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

These proposals also were included in President Obama's Proposed Fiscal Year 2012 Budget. It is unclear whether these or similar changes will be enacted. The passage of this legislation or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Lower oil and gas prices and other factors have resulted in ceiling test writedowns in the past and may in the future result in additional ceiling test writedowns or other impairments. We capitalize the costs to acquire, find and develop our oil and gas properties under the full cost accounting method. The net capitalized costs of our oil and gas properties may not exceed the present value of estimated future net cash flows from proved reserves. If net capitalized costs of our oil and gas properties exceed this limit, we must charge the amount of the excess to earnings. This is called a "ceiling test writedown." We recorded a ceiling test writedown of approximately $1.3 billion ($854 million after-tax) as of March 31, 2009. Although a ceiling test writedown does not impact cash flows from operations, it does reduce our stockholders' equity. Once recorded, a ceiling test writedown is not reversible at a later date even if oil and gas prices increase.

We may experience further ceiling test writedowns or other impairments in the future. The risk that we will be required to further writedown the carrying value of our oil and gas properties increases when oil and gas prices are low or volatile. In addition, writedowns may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. Any future ceiling test cushion would be subject to fluctuation as a result of acquisition or divestiture activity.

There is limited transportation and refining capacity for our black and yellow wax crude oil, which may limit our ability to sell our current production or to increase our production in the Uinta Basin. Most of the crude oil we produce in the Uinta Basin is known as "black wax" or "yellow wax" because it has higher paraffin content than crude oil found in most other major North American basins. Due to its wax content, it must remain heated during shipping, so our transportation options are limited. Currently, the oil is transported by truck to refiners in the Salt Lake City area. We currently have agreements in place with area refiners that secure base load sales of substantially all of our expected production in the Uinta Basin through the end of 2012. In addition, we have executed long-term supply agreements with Tesoro and HollyFrontier, who are expanding their local refineries. Our commitments begin in 2013 and 2014, respectively. However, the inability of Tesoro or HollyFrontier to complete their expansions or an extended loss of any of our largest purchasers could have a material adverse effect on us because there are limited purchasers of our black and yellow wax crude oil.

The oil and gas business involves many operating risks that can cause substantial losses. Our oil and gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and gas, including the risk of:

- fires and explosions;
- blow-outs;
- uncontrollable or unknown flows of oil, gas, or well fluids;
- pipe or cement failures and casing collapses;
- pipeline ruptures;
- adverse weather conditions or natural disasters;
- discharges of toxic gases;
- buildup of naturally occurring radioactive materials;
- vandalism; and
- environmental damages caused by previous owners of property we purchase and lease.

If any of these events occur, we could incur substantial losses as a result of:

- injury or loss of life;
- severe damage or destruction of property and equipment, and oil and gas reservoirs;
- pollution and other environmental damage;
- investigatory and clean-up responsibilities;
- regulatory investigation and penalties or lawsuits;
- suspension of our operations; and
- repairs to resume operations.

Further, offshore and deepwater operations are subject to a variety of additional operating risks, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions could cause substantial damage to facilities and interrupt production. In addition, some of our offshore operations, and most of our deepwater and international operations, are dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities that we do not own. Necessary infrastructures have been in the past, and may be in the future, temporarily unavailable due to adverse weather conditions or other reasons, or they may not be available to us in the future on acceptable terms or at all.

In connection with our operations, we generally require our contractors, which include the contractor, its parent, subsidiaries and affiliate companies, its subcontractors, their agents, employees, directors and officers, to agree to indemnify us for injuries and deaths of their employees, contractors and subcontractors and any property damage suffered by the contractors. There may be times, however, that we are required to indemnify our contractors for injuries and other losses resulting from the events described above, which indemnification claims could result in substantial losses to us.

The occurrence of any of the foregoing events and any costs or liabilities incurred as a result of such events, if uninsured or in excess of our insurance coverage or not indemnified, could reduce revenue and the funds available to us for our exploration, exploitation, development and production activities and could, in turn, have a material adverse effect on our business, financial condition and results of operations. See also "— *We may not be insured against all of the operating risks to which our business is exposed.*"

We may not be insured against all of the operating risks to which our business is exposed. Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, such as well blowouts, explosions, oil spills, releases of gas or well fluids, fires, pollution and adverse weather conditions, which could result in substantial losses to us. See also "— *The oil and gas business involves many operating risks that can cause substantial losses.*" We maintain insurance against many, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our insurance coverage will adequately protect us against liability from all potential consequences, damages and losses.

We currently have insurance policies covering our onshore and offshore operations that include coverage for general liability, excess liability, physical damage to our oil and gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employers' liability and other coverages. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. For example, we maintain operators extra expense coverage provided by third-party insurers for obligations, expenses or claims that we may incur from a sudden incident that results in negative environmental effects, including obligations, expenses or claims related to seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operators extra expense coverage would be our primary source of coverage, with the general liability and excess liability coverage referenced above also providing certain coverage.

In the event we make a claim under our insurance policies, we will be subject to the credit risk of the insurers. Volatility and disruption in the financial and credit markets may adversely affect the credit quality of our insurers and impact their ability to pay claims.

Further, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse effect on our business, financial condition and results of operations.

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. We deliver oil and gas through gathering systems and pipelines that we do not own. The lack of availability of capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our production through some firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical or other reasons, or may not be available to us in the future at a price that is acceptable to us. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition, results of operations and cash flows.

Exploration in deepwater involves significant financial risks, and we may be unable to obtain the drilling rigs or support services necessary for our deepwater drilling and development programs in a timely manner or at acceptable rates. Much of the deepwater play lacks the physical and oilfield service infrastructure necessary for production. As a result, development of a deepwater discovery may be a lengthy process and requires substantial capital investment, and it is difficult to estimate the timing of our production. Because of the size of significant projects in which we invest, we may not serve as the operator. As a result, we may have limited ability to exercise influence over operations related to these projects or their associated costs. Our dependence on the operator and other working interest owners for these deepwater projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital or lead to unexpected future losses.

We have risks associated with our non-U.S. operations. Ownership of property interests and production operations in areas outside the United States are subject to the various risks inherent in international operations. These risks may include:

- currency restrictions and exchange rate fluctuations;
- loss of revenue, property and equipment as a result of expropriation, nationalization, war or insurrection or other changes in government;
- increases in taxes and governmental royalties;
- forced renegotiation of, or unilateral changes to, or termination of contracts with governmental entities and quasi-governmental agencies;
- changes in laws and policies governing operations of non-U.S. based companies;
- our limited ability to influence or control the operation or future development of these non-operated properties;
- the operator's expertise or other labor problems;
- difficulties enforcing our rights against a governmental entity because of the doctrine of sovereign immunity and foreign sovereignty over international operations; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

Our international operations also may be adversely affected by the laws and policies of the United States affecting foreign trade, taxation and investment. In addition, if a dispute arises with respect to our international operations, we may be subject to the exclusive jurisdiction of non-U.S. courts or may not be successful in subjecting non-U.S. persons to the jurisdiction of the courts of the United States.

We may be subject to risks in connection with acquisitions. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and gas prices and their appropriate differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections will not likely be performed on every well or facility, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems.

Competition for experienced technical personnel may negatively impact our operations or financial results. Our continued drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced explorationists, engineers, geologists and other professionals. Competition for these professionals remains strong. We are likely to continue to experience increased costs to attract and retain these professionals.

Competition in the oil and gas industry is intense. Our competitors include major oil and gas companies, independent oil and gas companies, individual producers, national oil companies and financial buyers. Many of our competitors have greater and more diverse resources than we do. In addition, high commodity prices and stiff competition for acquisitions have in the past, and may in the future, significantly increase the cost of available properties.

We depend on computer and telecommunications systems and failures in our systems or cyber security attacks could significantly disrupt our business operations. We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with the business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties, to our computing and communications infrastructure, or our information systems could significantly disrupt our business operations.

Our certificate of incorporation, bylaws, some of our arrangements with employees and Delaware law contain provisions that could discourage an acquisition or change of control of our company. Our certificate of incorporation and bylaws contain provisions that may make it more difficult to effect a change of control of our company, to acquire us or to replace incumbent management. In addition, our change of control severance plan and agreements, our omnibus stock plans and our incentive compensation plan contain provisions that provide for severance payments and accelerated vesting of benefits, including accelerated vesting of restricted stock, restricted stock units and stock options, upon a change of control. Section 203 of the Delaware General Corporation Law also imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions could discourage or prevent a change of control or reduce the price our stockholders receive in an acquisition of our company.

Item 1B. *Unresolved Staff Comments*

None.

Item 3. *Legal Proceedings*

In August 2010, we received a Notice of Violation (NOV) from the EPA alleging that we failed to provide adequate financial assurance for water injection wells falling under EPA jurisdiction that are located at our Monument Butte field in Duchesne County, Utah (Monument Butte). The injection wells are part of an enhanced oil recovery project designed to optimize production from Monument Butte. Regulations under the Safe Drinking Water Act, or SDWA, require operators of injection wells to file proof of financial assurance annually to cover the costs to plug and abandon the injection wells. The NOV alleges that our 2010 filing (for 2009) did not meet the financial ratio tests which are acceptable as one form of required financial assurance under SDWA regulations. Upon receipt of the NOV, we promptly complied with the EPA's request to put in place alternate financial assurance for the wells. We have held preliminary discussions with the EPA regarding potential settlement of this matter; however, the EPA has determined that the matter required a referral to the Department of Justice (DOJ), and could not be resolved administratively within the EPA's settlement authority under the SDWA. The Company has yet to engage with DOJ concerning how and when this matter might be resolved. The NOV was administrative in nature and did not contain any allegations of environmental spills, releases or pollution. Although the outcome of this matter cannot be predicted with certainty, we do not expect it to have a material adverse effect on our financial position, cash flows or results of operations.

In addition to the foregoing matter, we have been named as a defendant in a number of lawsuits and are involved in various other disputes, all arising in the ordinary course of our business, such as (1) claims from royalty owners for disputed royalty payments, (2) commercial disputes, (3) personal injury claims and (4) property damage claims. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

Item 4. *Mine Safety Disclosures*

Not applicable.

Executive Officers of the Registrant

The following table sets forth the names of, ages (as of February 15, 2012) of and positions held by our executive officers. Our executive officers are appointed annually and serve at the discretion of our Board of Directors.

Name	Age	Position	Total Years of Service with Newfield
Lee K. Boothby	50	President, Chief Executive Officer and Chairman of the Board	12
Gary D. Packer	49	Executive Vice President and Chief Operating Officer	16
Terry W. Rathert	59	Executive Vice President and Chief Financial Officer	22
George T. Dunn	54	Vice President — Mid-Continent	19
Daryll T. Howard	49	Vice President — Rocky Mountains	15
John H. Jasek	42	Vice President — Onshore Gulf Coast	12
William D. Schneider	60	Vice President — Gulf of Mexico and International	23
John D. Marziotti	48	General Counsel and Secretary	8
Brian L. Rickmers	43	Chief Commercial Officer, Controller and Assistant Secretary	18

Lee K. Boothby was named Chairman of the Board of Directors in May 2010, Chief Executive Officer in May 2009 and to the role of President in February 2009. Prior to this and until 2007, he was Senior Vice President — Acquisitions and Business Development. From 2002 to 2007, he was Vice President — Mid-Continent. From 1999 to 2001, Mr. Boothby was Managing Director — Newfield Exploration Australia Ltd. and managed our operations in the Timor Sea (divested in 2003) from Perth, Australia. Prior to joining Newfield in 1999, Mr. Boothby worked for Cockrell Oil Corporation, British Gas and Tenneco Oil Company. He serves as a board member for America's Natural Gas Alliance and the Independent Petroleum Association of America (IPAA). In June 2011, he was named Chairman of the Board of the American Exploration & Production Council. He is a member of the Louisiana State University Craft & Hawkins Department of Petroleum Engineering Advisory Committee and also is a member of Rice University Jones Graduate School of Business Council of Overseers. He holds a degree in Petroleum Engineering from Louisiana State University and an M.B.A. from Rice University.

Gary D. Packer was promoted to the position of Executive Vice President and Chief Operating Officer in May 2009. Prior thereto, he was promoted from Gulf of Mexico General Manager to Vice President — Rocky Mountains in November 2004. Mr. Packer joined the Company in 1995. Prior to joining Newfield, Mr. Packer worked for Amerada Hess in both the Rocky Mountain and Gulf of Mexico divisions. Prior to these roles, he worked for Tenneco Oil Company. He holds a degree in Petroleum and Natural Gas Engineering from Penn State University.

Terry W. Rathert was promoted from Senior Vice President to Executive Vice President in May 2009 and previously was promoted from Vice President to Senior Vice President in November 2004. Prior to being named

Chief Financial Officer in early 2000, Mr. Rathert served as Vice President — Planning and Administration and Secretary since July 1997. From 1992 to 1997, he served as Vice President, Chief Financial Officer and Secretary and from 1989 to 1992 he coordinated the Company's planning and marketing activities. Mr. Rathert was one of our founding members. Prior to Newfield, Mr. Rathert was Director of Economic Planning and Analysis for Tenneco Oil Exploration and Production Company. Mr. Rathert serves on Texas A&M University's Petroleum Engineering Department's Industry Board, the Board of Directors of the Greater Houston YMCA, as treasurer of the American Exploration and Production Council, on the Board of the Houston Energy Finance Group and is a member of the Texas Southeast Region of Trustees for the Independent Producers Association of America. Mr. Rathert has a degree in Petroleum Engineering from Texas A&M University and has completed the Management Program at Rice University.

George T. Dunn was named Vice President — Mid-Continent in October 2007. He managed our onshore Gulf Coast operations from 2001 to October 2007, and was promoted from General Manager to Vice President in November 2004. Before managing our Gulf Coast operations, Mr. Dunn was the general manager of our Western Gulf of Mexico division. Prior to joining Newfield in 1992, Mr. Dunn was employed by Meridian Oil Company and Tenneco Oil Company. He serves as a member of the Board of Directors of the Oklahoma Independent Petroleum Association and holds a degree in Petroleum Engineering from the Colorado School of Mines.

Daryll T. Howard was promoted to the position of Vice President — Rocky Mountains in May 2009. Mr. Howard joined Newfield in 1996. Prior to his promotion on May 7, 2009, Mr. Howard served as East Team Rocky Mountain Asset Manager since June 2008. Prior thereto, Mr. Howard assisted in establishing Newfield's Malaysia office and was instrumental in the success and growth of Newfield's international operations. Mr. Howard also previously held several positions of increasing breadth and responsibility in our Gulf of Mexico business unit. He holds B.S. and M.S. degrees in Petroleum Engineering from Louisiana State University.

John H. Jasek was reappointed as Vice President — Onshore Gulf Coast in February 2011. Prior to that, he was reappointed as Vice President — Gulf of Mexico in December 2008. Mr. Jasek served as Vice President — Gulf Coast from October 2007 until December 2008 while also serving as the manager of our onshore Gulf Coast operations. He previously managed our Gulf of Mexico operations from March 2005 until October 2007, and was promoted from General Manager to Vice President in November 2006. Prior to March 2005, he was a Petroleum Engineer in the Western Gulf of Mexico. Prior to joining Newfield, Mr. Jasek worked for Anadarko Petroleum Corporation and Amoco Production Company. He has a degree in Petroleum Engineering from Texas A&M University.

William D. Schneider was appointed Vice President — Gulf of Mexico and International in February 2011. Prior to that, he served as Vice President — Onshore Gulf Coast and International from December 2008 until February 2011. He has managed our international operations since May 2000. He served as Manager — Exploration from 1992 to 1997, Technical Coordinator from 1991 to 1992 and was a geologist from 1989 to 1992. Mr. Schneider was one of our founding members. Prior to Newfield, Mr. Schneider was Division Geologist in the Western Gulf Division of Tenneco Oil Exploration and Production Company. Mr. Schneider holds B.A. and M.A. degrees in Geology from Boston University.

John D. Marziotti was promoted to General Counsel in August 2007 and was named Secretary in May 2008. From November 2003, when he joined our company, until August 2007 he held the position of Legal Counsel. Prior to joining Newfield, he was a shareholder of the law firm of Strasburger & Price, LLP. Mr. Marziotti holds a B.A. from the College of Charleston and a J.D. from Southern Methodist University.

Brian L. Rickmers was promoted to Chief Commercial Officer in January 2012. Prior to this promotion, Mr. Rickmers was Corporate Controller and Assistant Secretary for the past ten years and will continue in that role for the immediate future. Prior to this promotion in 2002, he served in various capacities from Accountant to Financial Analyst and Assistant Controller for Newfield. Mr. Rickmers holds a B.B.A. degree in Accounting from Texas A&M University and is a certified public accountant.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Market for Common Stock

Our common stock is listed on the New York Stock Exchange under the symbol "NFX." The following table sets forth, for each of the periods indicated, the high and low reported sales price of our common stock on the NYSE.

	High	Low
2010:		
First Quarter	$55.20	$47.21
Second Quarter	60.50	44.81
Third Quarter	57.99	46.11
Fourth Quarter	73.58	56.70
2011:		
First Quarter	$77.93	$65.72
Second Quarter	77.32	62.10
Third Quarter	73.30	39.16
Fourth Quarter	47.40	34.42
2012:		
First Quarter (through February 21, 2012)	$42.47	$36.89

On February 21, 2012, the last reported sales price of our common stock on the NYSE was $42.25. As of that date, there were approximately 2,164 holders of our common stock.

Dividends

We have not paid any cash dividends on our common stock and do not intend to do so in the foreseeable future. We intend to retain earnings for the future operation and development of our business. Any future cash dividends to holders of our common stock would depend on future earnings, capital requirements, our financial condition and other factors determined by our Board of Directors. The covenants contained in our credit facility and in the indentures governing our 6⅝% Senior Subordinated Notes due 2014 and 2016, our 7⅛% Senior Subordinated Notes due 2018, our 6⅞% Senior Subordinated Notes due 2020, and our 5¾% Senior Notes due 2022 could restrict our ability to pay cash dividends. See "Contractual Obligations" under Item 7 of this report and Note 8, "Debt," to our consolidated financial statements in Item 8 of this report.

Issuer Purchases of Equity Securities

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2011.

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet be Purchased under the Plans or Programs
October 1 — October 31, 2011	4,280	$39.74	—	—
November 1 — November 30, 2011	9,539	41.49	—	—
December 1 — December 31, 2011	1,822	46.13	—	—
Total	15,641	$41.55	—	—

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards and restricted stock units. These repurchases were not part of a publicly announced program to repurchase shares of our common stock.

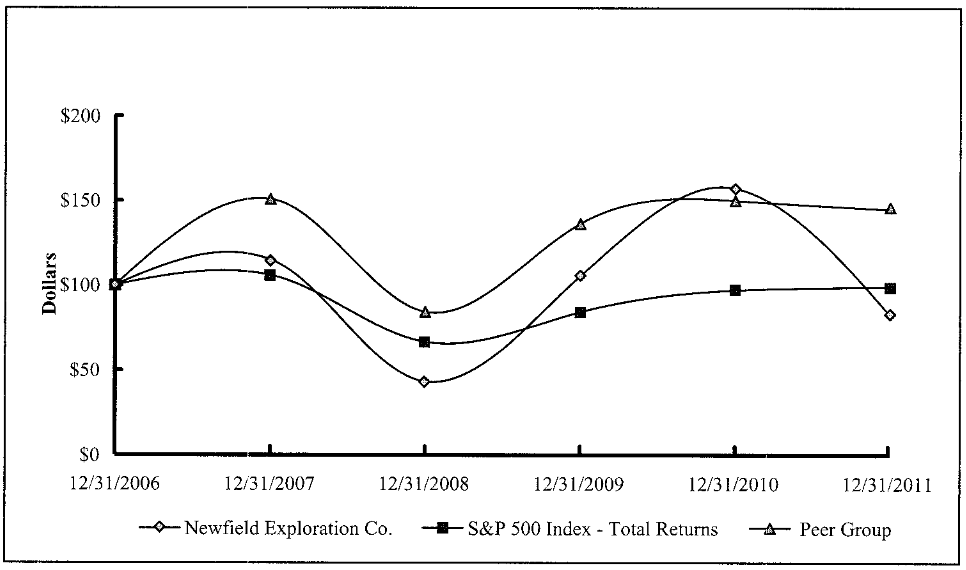
Stockholder Return Performance Presentation

The performance presentation shown below is being furnished pursuant to applicable rules of the SEC. As required by these rules, the performance graph was prepared based upon the following assumptions:

- $100 was invested in our common stock, the S&P 500 Index, and our peer group on December 31, 2006 at the closing price on such date;
- investment in our peer group was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of the period; and
- dividends were reinvested on the relevant payment dates.

Peer Group. Our peer group consists of Cabot Oil & Gas Corporation, Cimarex Energy Company, Denbury Resources Inc., EXCO Resources, Inc., Forest Oil Corporation, Noble Energy, Inc., Pioneer Natural Resources Company, Plains Exploration & Production Company, Range Resources Corporation, SandRidge Energy, Inc., Southwestern Energy Company and Ultra Petroleum Corp.

Comparison of 5 Year Cumulative Total Return



Total Return Analysis	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
Newfield Exploration Company	$ 100.00	$ 114.71	$ 42.98	$ 104.96	$ 156.92	$ 82.11
Peer Group	$ 100.00	$ 150.47	$ 83.91	$ 136.03	$ 149.61	$ 144.49
S&P 500	$ 100.00	$ 105.50	$ 66.47	$ 84.05	$ 96.71	$ 98.75

Item 6. ***Selected Financial Data***

SELECTED FIVE-YEAR FINANCIAL AND RESERVE DATA

The following table shows selected consolidated financial data derived from our consolidated financial statements and selected reserve data derived from our supplementary oil and gas disclosures set forth in Item 8 of this report. The data should be read in conjunction with Items 1 and 2, *"Business and Properties* — Reserves" and Item 7, *"Management's Discussion and Analysis of Financial Condition and Results of Operations,"* of this report.

	Year Ended December 31,				
	2011(1)	2010(1)	2009(1)	2008	2007
	(In millions, except per share data)				
Income Statement Data:					
Oil and gas revenues	$ 2,471	$ 1,883	$ 1,338	$ 2,225	$1,783
Income (loss) from continuing operations	539	523	(542)	(373)	172
Net income (loss)	539	523	(542)	(373)	450
Earnings (loss) per share:					
Basic —					
Income (loss) from continuing operations	4.03	3.97	(4.18)	(2.88)	1.35
Net income (loss)	4.03	3.97	(4.18)	(2.88)	3.52
Diluted —					
Income (loss) from continuing operations	3.99	3.91	(4.18)	(2.88)	1.32
Net income (loss)	3.99	3.91	(4.18)	(2.88)	3.44
Weighted-average number of shares outstanding for basic earnings (loss) per share	134	132	130	129	128
Weighted-average number of shares outstanding for diluted earnings (loss) per share	135	134	130	129	131
Cash Flow Data:					
Net cash provided by continuing operating activities	$ 1,589	$ 1,630	$ 1,578	$ 854	$1,166
Net cash used in continuing investing activities	(2,236)	(1,951)	(1,356)	(2,253)	(865)
Net cash provided by (used in) continuing financing activities	684	282	(168)	1,173	(117)
Balance Sheet Data (at end of period):					
Total assets	$ 8,991	$ 7,494	$ 6,254	$ 7,305	$6,986
Long-term debt	3,006	2,304	2,037	2,213	1,050
Proved Reserves Data (at end of period):					
Oil and condensate (MMBbls)	263	204	169	140	114
Natural gas (Bcf)	2,333	2,492	2,605	2,110	1,810
Total proved reserves (Bcfe)	3,911	3,712	3,616	2,950	2,496
Present value of estimated future after-tax net cash flows	$ 5,981	$ 4,754	$ 2,864	$ 2,929	$4,531

(1) Effective December 31, 2009, we adopted revised authoritative accounting and disclosure requirements for oil and gas reserves. As a result, 2011, 2010 and 2009 disclosures are not on a basis comparable to the prior years. Please see Item 7, *"Management's Discussion and Analysis of Financial Condition and Results of Operations* — New Accounting Requirements," of this report.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Overview

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. Our principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and onshore Texas. Internationally, we focus on offshore oil developments in Malaysia and China.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. Prices for oil and gas fluctuate widely. Oil and gas prices affect:

- the amount of cash flows available for capital expenditures;
- our ability to borrow and raise additional capital; and
- the quantity of oil and gas that we can economically produce.

To maintain and grow our production and cash flows, we must continue to develop existing proved reserves and locate or acquire new oil and gas reserves to replace those reserves being produced. The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and gas reserves. We use the full cost method of accounting for our oil and gas activities.

Operational Highlights. Significant 2011 operational highlights include the following:

- In May 2011, we closed two separate transactions in the Central Basin (north and adjacent to Monument Butte) for approximately $303 million and added approximately 65,000 net acres, giving us interest in approximately 230,000 net acres in the Uinta Basin;
- In late 2011 and early 2012, we announced two separate, long-term agreements (7 and 10 years, respectively) with area refiners adding 38,000 BOPD of refining capacity beginning in 2013 and 2014;
- By year-end 2011, we had assembled more than 125,000 net acres in the "oily" Cana Woodford play, located in the Anadarko Basin; and
- Production commenced in late 2011 from two new offshore developments in Malaysia — East Piatu and Puteri, which are now providing combined net production of approximately 11,000 BOEPD as of February 15, 2012.

Financial Highlights. Significant 2011 financial highlights include the following:

- For 2011, we had revenues of $2.5 billion, 31% higher than 2010;
- For 2011, we recorded net income of $539 million, or $3.99 per diluted share;
- Production for the full year of 2011 was 293 Bcfe, an increase of 3% over 2010 production volumes;
- Oil and liquids production grew more than 20% over 2010 levels and comprised 40% of our total production;
- At year-end 2011, our proved reserves were 3.9 Tcfe and probable reserves were 2.6 Tcfe, which reflects growth of 5% and 4%, respectively, over the prior year;
- During 2011, our proved oil reserves increased nearly 30% and proved natural gas reserves declined by 6% when compared to year-end 2010;
- Our oil liftings in the fourth quarter of 2011 were 6 million barrels, or an average of approximately 64,000 BOPD, which is approximately 9,000 BOPD higher than the third quarter of 2011 and approximately 28% higher than the fourth quarter of 2010; and
- During 2011, we monetized approximately $406 million in sales of non-strategic assets and executed contracts to monetize an additional $335 million.

Results of Operations

Revenues. All of our revenues are derived from the sale of our oil and gas production and do not include the effects of the settlements of our hedges. Please see Note 4, "Derivative Financial Instruments," to our consolidated financial statements in Item 8 of this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Our revenues may vary significantly from period-to-period as a result of changes in commodity prices or volumes of production sold. In addition, substantially all of the crude oil from our operations offshore Malaysia and China is produced into FPSOs and "lifted" and sold periodically as barge quantities are accumulated. Revenues are recorded when oil is lifted and sold, not when it is produced into the FPSO. As a result, the timing of liftings may impact period-to-period results.

Revenues of $2.5 billion for 2011 were 31% higher than 2010. Approximately half of the increase in revenue for 2011 was due to higher average realized oil prices and half of the increase resulted from increased oil production. Revenues of $1.9 billion for 2010 were 41% higher than 2009. For 2010, approximately 60% of the revenue increase was due to higher average realized oil and gas prices, 25% related to increased oil production and the remainder resulted from increased natural gas production.

	Year Ended December 31,		
	2011	2010	2009
Production:(1)(2)			
Domestic:			
Natural gas (Bcf)	175.1	186.9	168.4
Oil, condensate and NGLs (MBbls)	12,943	10,016	8,045
Total (Bcfe)	252.7	247.0	216.7
International:			
Natural gas (Bcf)	0.1	—	—
Oil, condensate and NGLs (MBbls)	6,715	6,057	6,120
Total (Bcfe)	40.4	36.3	36.7
Total:			
Natural gas (Bcf)	175.2	186.9	168.4
Oil, condensate and NGLs (MBbls)	19,658	16,073	14,165
Total (Bcfe)	293.1	283.3	253.4
Average Realized Prices:(2)(3)			
Domestic:			
Natural gas (per Mcf)	$ 4.05	$ 4.09	$ 3.38
Oil, condensate and NGLs (per Bbl)	79.29	65.35	49.52
Natural gas equivalent (per Mcfe)	6.89	5.78	4.47
International:			
Natural gas (per Mcf)	$ 3.95	$ —	$ —
Oil, condensate and NGLs (per Bbl)	108.51	75.27	59.72
Natural gas equivalent (per Mcfe)	18.06	12.54	9.95
Total:			
Natural gas (per Mcf)	$ 4.05	$ 4.09	$ 3.38
Oil, condensate and NGLs (per Bbl)	89.27	69.09	53.93
Natural gas equivalent (per Mcfe)	8.43	6.65	5.28

(1) Represents volumes lifted and sold regardless of when produced. Excludes natural gas produced and consumed in our operations of 6.8 Bcfe in 2011, 5.3 Bcfe in 2010 and 4.0 Bcfe in 2009.

(2) Historically, we reported natural gas liquids (NGLs) volumes in natural gas production volumes. Effective January 1, 2011, we began reporting our NGLs in barrels and included NGLs with total oil and condensate production. As such, all production volumes and average realized prices for periods prior to 2011 have been reclassified for comparability between periods.

(3) Had we included the effects of hedging contracts not designated for hedge accounting, our average realized price for total natural gas would have been $5.43, $5.62 and $6.43 per Mcf for 2011, 2010 and 2009, respectively. Our total oil and condensate average realized price would have been $86.88, $77.86 and $78.19 per Bbl for 2011, 2010 and 2009, respectively.

Domestic Production. Our 2011 domestic oil and gas production, stated on a natural gas equivalent basis, increased 2% over 2010 production primarily due to increased production of 8% in our Rocky Mountain and Mid-Continent divisions as a result of continued successful development drilling efforts, partially offset by production decreases in our onshore Gulf Coast and Gulf of Mexico deepwater divisions due to natural field decline and weather- and equipment-related delays.

Our 2010 domestic oil and gas production, stated on a natural gas equivalent basis, increased 14% over 2009 production primarily due to increased production of 18 Bcfe in our Mid-Continent division as a result of continued successful development drilling efforts, combined with increased production of 13 Bcfe as a result of the further development of our Gulf of Mexico deepwater discoveries.

International Production. Our 2011 international oil production increased over 2010 levels primarily due to an increase in production of 13% in Malaysia as a result of new field developments on PM 323 and PM 329 and the timing of liftings. Our 2010 international oil production decreased slightly from 2009 levels primarily due to the timing of liftings from our oil production in Malaysia.

Operating Expenses. We believe the most informative way to analyze changes in our operating expenses from period-to-period is on a unit-of-production, or per Mcfe, basis.

Year ended December 31, 2011 compared to December 31, 2010

The following table presents information about our operating expenses for the two-year period ended December 31, 2011.

	Unit-of-Production			Total Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2011	2010		2011	2010	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 1.42	$1.07	33%	$ 358	$ 264	35%
Production and other taxes	0.27	0.18	50%	68	44	54%
Depreciation, depletion and amortization	2.46	2.08	18%	621	515	21%
General and administrative	0.71	0.61	16%	180	150	20%
Ceiling test and other impairments	—	0.03	(100)%	—	7	(100)%
Other	—	0.04	(100)%	—	10	(100)%
Total operating expenses	4.85	4.01	21%	1,227	990	24%
International:						
Lease operating	$ 2.36	$1.72	37%	$ 95	$ 62	52%
Production and other taxes	6.49	2.25	188%	262	82	220%
Depreciation, depletion and amortization	3.60	3.56	1%	146	129	12%
General and administrative	0.13	0.17	(24)%	5	6	(11)%
Total operating expenses	12.58	7.70	63%	508	279	82%
Total:						
Lease operating	$ 1.55	$1.15	35%	$ 453	$ 326	39%
Production and other taxes	1.13	0.44	157%	330	126	162%
Depreciation, depletion and amortization	2.62	2.27	15%	767	644	19%
General and administrative	0.63	0.55	15%	185	156	19%
Ceiling test and other impairments	—	0.03	(100)%	—	7	(100)%
Other	—	0.03	(100)%	—	10	(100)%
Total operating expenses	5.92	4.47	32%	1,735	1,269	37%

Domestic Operations. Our domestic operating expenses for 2011, stated on a Mcfe basis, increased 21% over those for 2010. The components of the significant period-to-period change are as follows:

- Lease operating expense (LOE) includes normally recurring expenses to operate and produce our oil and gas wells, non-recurring well workover and repair-related expenses and the costs to transport our production to the applicable sales points. The increase in domestic LOE per Mcfe resulted from a 50% ($0.26 per Mcfe) increase in the normally recurring portion of our LOE. Recurring LOE in our Rocky Mountain division accounted for approximately 60% of the increase due to increased water handling and overall operating and service-related costs in the basins in which we operate. In addition, LOE increased ($0.08 per Mcfe) due to increased transportation costs resulting from the commencement of firm transportation contracts in our Mid-Continent division throughout 2010.
- Production and other taxes per Mcfe increased due to a 21% increase in realized oil prices during 2011, coupled with a 4% increase in oil and natural gas production subject to production taxes.
- Since late 2009, the shift of our capital investments toward the oil plays in our portfolio has resulted in an increase in our depreciation, depletion and amortization (DD&A) rate. The increase in total DD&A expense is related to the increase in the DD&A rate, coupled with the slight increase in our production volumes during 2011 compared to 2010.
- General and administrative (G&A) expense per Mcfe increased during 2011 due to employee-related expenses associated with our growing domestic work force and approximately $7 million of legal expenses related to litigation in which we are the plaintiff. During 2011, we capitalized $83 million ($0.33 per Mcfe) of direct internal costs as compared to $61 million ($0.25 per Mcfe) during 2010.
- During the fourth quarter of 2010, we recorded an impairment of $7 million ($0.03 per Mcfe) for certain claims related to the bankruptcy proceedings associated with TXCO Resources Inc.
- Other expenses for 2010 included the early redemption premium of $12 million associated with the tender offer and repurchase of our $175 million aggregate principal amount of 7⅝% Senior Notes due 2011, partially offset by the $2 million cash received resulting from the termination of the associated interest rate swap.

International Operations. Our international operating expenses for 2011, stated on a Mcfe basis, increased 63% over 2010. The components of the significant period-to-period change are as follows:

- LOE per Mcfe increased due to non-recurring pipeline and facilities repair in Malaysia, fixed production costs associated with certain of our production sharing contracts (PSCs) in Malaysia and increased overall operating service costs from the various PSCs during 2011 compared to 2010.
- Production and other taxes per Mcfe increased significantly due to an increase, per the terms of the PSCs, in the tax rate per barrel of oil lifted and sold as a result of the 44% increase in realized oil prices in 2011.
- Total DD&A expense increase was driven by the 11% increase in volumes during 2011 compared to 2010.

Year ended December 31, 2010 compared to December 31, 2009

The following table presents information about our operating expenses for the two-year period ended December 31, 2010.

	Unit-of-Production			Total Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2010	2009		2010	2009	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$1.07	$ 0.94	14%	$ 264	$ 203	30%
Production and other taxes	0.18	0.15	20%	44	33	36%
Depreciation, depletion and amortization	2.08	2.14	(3)%	515	463	11%
General and administrative	0.61	0.64	(5)%	150	139	8%
Ceiling test and other impairments	0.03	6.20	(100)%	7	1,344	(99)%
Other	0.04	0.03	33%	10	8	28%
Total operating expenses	4.01	10.10	(60)%	990	2,190	(55)%
International:						
Lease operating	$1.72	$ 1.53	12%	$ 62	$ 56	11%
Production and other taxes	2.25	0.82	174%	82	30	173%
Depreciation, depletion and amortization	3.56	3.39	5%	129	124	4%
General and administrative	0.17	0.14	21%	6	5	17%
Total operating expenses	7.70	5.88	31%	279	215	30%
Total:						
Lease operating	$1.15	$ 1.02	13%	$ 326	$ 259	26%
Production and other taxes	0.44	0.25	76%	126	63	102%
Depreciation, depletion and amortization	2.27	2.32	(2)%	644	587	10%
General and administrative	0.55	0.57	(4)%	156	144	8%
Ceiling test and other impairments	0.03	5.30	(99)%	7	1,344	(99)%
Other	0.03	0.03	—%	10	8	28%
Total operating expenses	4.47	9.49	(53)%	1,269	2,405	(47)%

Domestic Operations. Our domestic operating expenses for 2010, stated on a Mcfe basis, decreased 60% as compared to 2009 primarily due to the full cost ceiling test writedown recorded at March 31, 2009. The components of the significant period-to-period change are as follows:

- LOE per Mcfe increased 14% primarily due to increased product transportation costs resulting from the commencement of firm transportation contracts during late 2009 and throughout 2010 in our Mid-Continent division.
- Production and other taxes per Mcfe increased 20% primarily due to higher realized commodity prices during 2010.
- Total DD&A expense for 2010 increased 11% primarily as a result of the 14% increase in our production volumes during 2010 compared to 2009.
- Total G&A expense increased 8% primarily due to increased employee-related expenses associated with our growing domestic workforce. Employee-related expenses include incentive compensation expense which is based on our company performance in comparison with peer companies in our industry as defined in the incentive compensation plan in effect during 2010. During 2010, we capitalized $61 million ($0.25 per Mcfe) of direct internal costs as compared to $58 million ($0.27 per Mcfe) in 2009.
- During the fourth quarter of 2010, we recorded an impairment of $7 million ($0.03 per Mcfe) related to certain claims related to the bankruptcy proceedings associated with TXCO Resources Inc. In 2009, we recorded a ceiling test writedown of $1.3 billion ($6.20 per Mcfe) due to significantly lower natural gas prices at March 31, 2009.
- Other expenses for 2010 includes the early redemption premium of $12 million associated with the tender offer and repurchase of our $175 million aggregate principal amount of 7⅝% Senior Notes due 2011, partially offset by the $2 million cash received resulting from the termination of the associated interest rate swap. Other expenses for 2009 includes long-term rig contract termination fees.

International Operations. Our international operating expenses for 2010, stated on a Mcfe basis, increased 31% over the same period of 2009 primarily as a result of significantly higher production taxes during 2010 due to substantially higher realized oil prices. The components of the significant period-to-period change are as follows:

- LOE per Mcfe increased 12% primarily due to fixed production and operating costs associated with certain of our PSCs in Malaysia, a change in the mix of produced, lifted and sold production from various PSCs during 2010 compared to the same period of 2009 and increased workover activity.
- Production and other taxes per Mcfe increased significantly due to an increase, per the terms of the PSCs, in the tax rate per barrel of oil lifted and sold as a result of a 26% increase in realized oil prices during 2010.

Interest Expense. The following table presents information about interest expense for each of the years in the three-year period ended December 31, 2011:

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Gross interest expense:			
Credit arrangements	$ 11	$ 3	$ 8
Senior notes	11	2	12
Senior subordinated notes	152	149	102
Other	1	2	4
Total gross interest expense	175	156	126
Capitalized interest	(82)	(58)	(51)
Net interest expense	$ 93	$ 98	$ 75

The increase in gross interest expense in 2011 as compared to 2010 primarily resulted from increased borrowings under our credit arrangements and the September 2011 issuance of $750 million aggregate principal amount of 5 3⁄4% Senior Notes due 2022. The increase in gross interest expense in 2010 as compared to 2009 primarily resulted from the January 2010 issuance of $700 million aggregate principal amount of 6 7⁄8% Senior Subordinated Notes due 2020, partially offset by the tender and repurchase of our $175 million aggregate principal amount of 7 5⁄8% Senior Notes due 2011 during the first half of 2010 and lower outstanding borrowings under our credit arrangements during 2010. See Note 8, "Debt," to our consolidated financial statements in Item 8 of this report.

Interest expense related to unproved properties is capitalized into oil and gas properties. Capitalized interest increased in 2011 as compared to 2010 due to an increase in the average balance of unproved properties primarily resulting from the acquisition of assets in the Uinta Basin of Utah. Capitalized interest increased in 2010 as compared to 2009 due to an increase in the average balance of unproved properties primarily as a result of the Maverick Basin asset acquisition in February 2010.

Commodity Derivative Income. The significant fluctuations in commodity derivative income from period-to-period are due to the significant volatility of oil and gas prices and changes in our outstanding hedging contracts during these periods.

Taxes. The effective tax rates for the years ended December 31, 2011, 2010 and 2009 were 36%, 37% and 39%, respectively. Our effective tax rate for all periods was different than the federal statutory tax rate due to deductions that do not generate tax benefits, state income taxes and the differences between international and U.S. federal statutory rates. Our effective tax rate generally approximates 37%. Our effective tax rate for 2009 was impacted by the release of the valuation allowance related to the Malaysia tax benefit recorded in 2008.

Estimates of future taxable income can be significantly affected by changes in oil and gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

Liquidity and Capital Resources

We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this through successful drilling programs and property acquisitions. These activities require substantial capital expenditures. Lower prices for oil and gas may reduce the amount of oil and gas that we can economically produce, and can also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital, as further described below.

We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our capital budgets (excluding acquisitions) are created based upon our estimate of internally generated sources of cash, primarily cash flows from operations. Approximately 80% of our expected 2012 domestic oil and gas production (excluding NGLs) supporting the current 2012 capital budget is hedged. Our 2012 capital budget, excluding capitalized interest and overhead of $210 million, is approximately $1.5 to $1.7 billion and focuses on projects with higher return on investment and which we believe generate and lay the foundation for oil production growth in 2012 and thereafter. Substantially all of the 2012 budget is allocated to oil or liquids-rich projects.

Actual capital expenditure levels may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. We have the operational flexibility to react quickly with our capital expenditures to changes in circumstances and our cash flows from operations.

In May 2011, we closed two transactions to acquire assets in the Uinta Basin of Utah for a total of approximately $303 million. The acquisitions were funded with borrowings under our credit facility. During 2011, we received proceeds from the sale of certain non-strategic assets of approximately $406 million. We used the proceeds from these sales to reduce borrowings outstanding under our credit facility.

In September 2011, we sold $750 million of 5¾% Senior Notes due 2022 and received proceeds of $742 million (net of discount and offering costs). These notes were issued at 99.956% of par to yield 5¾%. We used the net proceeds to repay a portion of our then outstanding borrowings under our credit facility and money market lines of credit.

We continue to hold auction rate securities with a fair value of $32 million. We attempt to sell these securities every 7-28 days until the auctions succeed, the issuer calls the securities or the securities mature. We currently do not believe that the decrease in the fair value of these investments is permanent or that the failure of the auction mechanism will have a material impact on our liquidity given the amount of our available borrowing capacity under our credit arrangements. See Note 7, "Fair Value Measurements," to our consolidated financial statements in Item 8 of this report for more information regarding the auction rate securities.

Credit Arrangements. In June 2011, we entered into a new revolving credit facility that matures in June 2016 and provides for loan commitments of $1.25 billion from a syndicate of 13 financial institutions, led by JPMorgan Chase Bank, N.A., as agent. As of December 31, 2011, the largest individual commitment by any lender was 13% of total commitments.

In addition, subject to compliance with the restrictive covenants in our credit facility, we also have a total of $185 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions. For a more detailed description of the terms of our credit arrangements, please see Note 8, "Debt," to our consolidated financial statements in Item 8 of this report.

At February 21, 2012, we had no letters of credit outstanding under our credit facility. In addition, we had no outstanding borrowings under either our credit facility or our money market lines of credit. Our available borrowing capacity under our credit arrangements was approximately $1.4 billion as of February 21, 2012.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements and changes in the fair value of our outstanding commodity derivative instruments. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. Although we anticipate that our 2012 capital spending (excluding acquisitions) will correspond with our anticipated 2012 cash flows from operations and property sales proceeds, we may borrow and repay funds under our credit arrangements throughout the year since the timing of expenditures and the receipt of cash flows from operations do not necessarily match.

At December 31, 2011 and 2010, we had negative working capital of $157 million and $197 million, respectively. The changes in our working capital are primarily a result of the timing of the collection of receivables, drilling activities, payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations.

Cash Flows from Operations. Cash flows from operations are primarily affected by production and commodity prices, net of the effects of settlements of our derivative contracts and changes in working capital. We sell substantially all of our oil and gas production under floating price market sensitive contracts. We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months. See "— Oil and Gas Hedging" below.

We typically receive the cash associated with oil and gas sales within 45-60 days of production. As a result, cash flows from operations and income from operations generally correlate, but cash flows from operations are impacted by changes in working capital and are not affected by DD&A, ceiling test writedowns, other impairments or other non-cash charges or credits.

Our net cash flows from operations were approximately $1.6 billion in 2011, 2010 and 2009. Our working capital requirements change each year as a result of the timing of drilling activities, receivable collections from purchasers and joint interest partners, payments made by us to vendors and other operators, the timing and amount of advances received from our joint operations and the change in net cash receipts on derivative settlements.

Cash Flows from Investing Activities. Net cash used in investing activities for 2011 was $2.2 billion compared to $2.0 billion for 2010.

During 2011, we:

- spent $2.6 billion primarily for additions to oil and gas properties (including $304 million for acquisitions of oil and gas properties);
- received proceeds of $406 million from sales of non-strategic oil and gas assets; and
- redeemed investments of $2 million.

During 2010, we:

- spent $2.0 billion primarily for additions to oil and gas properties (including $313 million for acquisitions of oil and gas properties);
- received proceeds of $12 million from sales of oil and gas assets; and
- redeemed investments of $8 million.

Capital Expenditures. Our capital investments of $2.2 billion for 2011 increased 34% from our capital investments of $1.7 billion during 2010. These amounts exclude acquisitions of $321 million and $314 million in 2011 and 2010, respectively, and recorded asset retirement obligations of $33 million and $13 million in the respective years. Of the total $2.6 billion spent during 2011, we invested $1.5 billion in domestic exploitation and development, $237 million in domestic exploration (exclusive of exploitation and leasehold activity), $433 million in acquisitions of proved and unproved property (leasehold) and domestic leasing activity and $333 million outside the United States.

Our capital investments of $1.7 billion for 2010 increased 18% from our capital investments of $1.4 billion during 2009. These amounts exclude acquisitions of $314 million and $2 million in 2010 and 2009, respectively, and recorded asset retirement obligations of $13 million and $19 million in the respective years. Of the total $2.0 billion spent during 2010, we invested $1.2 billion in domestic exploitation and development, $248 million in domestic exploration (exclusive of exploitation and leasehold activity), $400 million in acquisitions of proved and unproved property (leasehold) and domestic leasing activity and $173 million outside the United States.

We have budgeted $1.5 to $1.7 billion for capital spending in 2012. The planned budget excludes capitalized interest and overhead of $210 million and acquisitions. Substantially all of the 2012 budget is allocated to oil or liquids-rich projects. Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable.

In May 2011, we closed two transactions to acquire assets in the Uinta Basin of Utah for a total of approximately $303 million. The assets include approximately 65,000 net acres, which are largely undeveloped and located in the Central Basin, which is just north of our Greater Monument Butte field.

Cash Flows from Financing Activities. Net cash flows provided by financing activities for 2011 were $684 million compared to $282 million for 2010.

During 2011, we:

- borrowed and repaid approximately $4.0 billion under our credit arrangements;
- issued $750 million aggregate principal amount of 5¾% Senior Notes due 2022 at 99.956% of par and paid $8 million in associated debt issue costs;
- paid $8 million in debt issue costs associated with our new revolving credit facility;
- received proceeds of $13 million from issuances of shares of our common stock upon the exercise of stock options; and
- repurchased $19 million of our common stock surrendered by employees to pay tax withholding upon the vesting of restricted stock and restricted stock unit awards.

During 2010, we:

- borrowed $1.5 billion and repaid $1.7 billion under our credit arrangements;
- issued $700 million aggregate principal amount of 6⅞% Senior Subordinated Notes due 2020 at 99.109% of par and paid $8 million in associated debt issue costs;
- repaid our $175 million aggregate principal amount of 7⅝% Senior Notes due 2011;
- received proceeds of $34 million from issuances of shares of our common stock upon the exercise of stock options; and
- repurchased $17 million of our common stock surrendered by employees to pay tax withholding upon the vesting of restricted stock and restricted stock unit awards.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of December 31, 2011.

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In millions)		
Debt:					
Revolving credit facility	$ 85	$ —	$ —	$ 85	$ —
Money market lines of credit	1	—	—	1	—
5 ¾% Senior Notes due 2022	750	—	—	—	750
6 ⅝% Senior Subordinated Notes due 2014	325	—	325	—	—
6 ⅝% Senior Subordinated Notes due 2016	550	—	—	550	—
7 ⅛% Senior Subordinated Notes due 2018	600	—	—	—	600
6 ⅞% Senior Subordinated Notes due 2020	700	—	—	—	700
Total debt	3,011	—	325	636	2,050
Other obligations:					
Interest payments(1)	1,367	186	559	287	335
Net derivative (assets) liabilities	(137)	(79)	(58)	—	—
Asset retirement obligations	145	10	29	24	82
Operating leases(2)	497	270	143	25	59
Firm transportation	589	70	228	144	147
Oil and gas activities(3)	133	—	—	—	—
Total other obligations	2,594	457	901	480	623
Total contractual obligations	$5,605	$457	$1,226	$1,116	$2,673

(1) Interest associated with our revolving credit facility and money market lines of credit was calculated using a weighted-average interest rate of 1.99% at December 31, 2011 and is included through the maturity of the facility.

(2) Includes non-cancellable agreements for office space and cancellable agreements for drilling rigs and other equipment, as well as certain service contracts. The majority of these obligations are related to contracts for hydraulic well-fracturing services and drilling rigs and are included at the gross contractual value. Due to our various working interests where these service contracts will be utilized, it is not feasible to estimate a net contractual obligation. Net payments under these contracts are accounted for as capital additions to our oil and gas properties and could be significantly less than the gross obligation disclosed.

(3) As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work-related commitments for, among other things, drilling wells, obtaining and processing seismic data, natural gas transportation and fulfilling other related commitments. At December 31, 2011, these work-related commitments totaled $133 million, all of which were attributable to our international business. Actual amounts by maturity are not included because their timing cannot be accurately predicted.

We have various oil and gas production volume delivery commitments that are related to our domestic operations. Given the size of our proved natural gas and oil reserves and production capacity in the respective divisions, we currently believe that we have sufficient reserves and production to fulfill these commitments. See Items 1 and 2, "*Business and Properties*" for a description of our production and proved reserves. As of December 31, 2011, our delivery commitments through 2020 were as follows:

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Natural gas (MMMBtus)	39,626	39,626	—	—	—
Oil (MBbls)	56,071	915	23,025	15,901	16,230

Credit Arrangements. Please see "— Liquidity and Capital Resources — *Credit Arrangements*" above for a description of our revolving credit facility and money market lines of credit.

Senior Notes

In September 2011, we issued $750 million aggregate principal amount of our 5¾% Senior Notes due 2022. We received net proceeds from the offering of $742 million.

Interest on our senior notes is payable semi-annually. The notes are unsecured and unsubordinated obligations and rank equally with all of our other existing and future unsecured and unsubordinated obligations. We may redeem some or all of our senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indenture governing our senior notes contains covenants that may limit our ability to, among other things:

- incur debt secured by liens;
- enter into sale/leaseback transactions; and
- enter into merger or consolidation transactions.

The indenture also provides that if any of our subsidiaries guarantee any of our indebtedness at any time in the future, then we will cause our senior notes to be equally and ratably guaranteed by that subsidiary.

Senior Subordinated Notes

In January 2010, we issued $700 million aggregate principal amount of our 6⅞% Senior Subordinated Notes due 2020. We received net proceeds from the offering of $686 million.

Interest on our senior subordinated notes is payable semi-annually. The notes are unsecured senior subordinated obligations that rank junior in right of payment to all of our present and future senior indebtedness.

We may redeem some or all of our 6⅝% notes due 2014 and our 6⅝% notes due 2016 at any time, in each case, at a redemption price stated in the applicable indenture governing the notes.

We may redeem some or all of our 7⅛% notes due 2018 at any time on or after May 15, 2013 at a redemption price stated in the indenture governing the notes. Prior to May 15, 2013, we may redeem all, but not part, of our 7⅛% notes at a make-whole redemption price plus accrued and unpaid interest to the date of redemption.

We may redeem some or all of our 6⅞% notes due 2020 at any time on or after February 1, 2015 at a redemption price stated in the indenture governing the notes. Prior to February 1, 2015, we may redeem some or all of the notes at a make-whole redemption price. In addition, before February 1, 2013, we may redeem up to 35% of our 6⅞% notes with the net cash proceeds of certain sales of our common stock at 106.875% of the principal amount, plus accrued and unpaid interest to the date of redemption.

The indenture governing our senior subordinated notes may limit our ability under certain circumstances to, among other things:

- incur additional debt;
- make restricted payments;
- pay dividends on or redeem our capital stock;
- make certain investments;
- create liens;
- engage in transactions with affiliates; and
- engage in mergers, consolidations and sales and other dispositions of assets.

Commitments under Joint Operating Agreements. Most of our properties are operated through joint ventures under joint operating or similar agreements. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a "working interest" basis. The joint operating agreement provides remedies to the operator if a non-operator does not satisfy its share of the contractual obligations. Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses.

Oil and Gas Hedging

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months to reduce our exposure to fluctuations in oil and gas prices. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive drilling programs. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions.

While the use of these hedging arrangements limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty, and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate hedging arrangements with that counterparty. At December 31, 2011, Barclays Bank PLC, Morgan Stanley Capital Group Inc., JPMorgan Chase Bank, N.A., Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to approximately 86% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

A significant number of the counterparties to our hedging arrangements are also lenders under our credit facility. Our credit facility, senior notes, senior subordinated notes and substantially all of our hedging arrangements contain provisions that provide for cross defaults and acceleration of those debt and hedging instruments in certain situations.

Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX. Historically, a majority of our hedged oil and gas production has been sold at market prices that have had a high positive correlation to the settlement price for such hedges.

The price that we receive for natural gas production from the Gulf of Mexico and onshore Gulf Coast, after basis differentials, transportation and handling charges, typically averages $0.25-$0.50 per MMBtu less than the Henry Hub Index. Realized natural gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average 90-95% of the Henry Hub Index. In the Rocky Mountains, we hedged basis associated with approximately 5 Bcf of our natural gas production from January 2012 through December 2012 to lock in the differential at a weighted average of $0.91 per MMBtu less than the Henry Hub Index. In total, this hedge and the 8,000 MMBtus per day we have sold on a fixed physical basis for the same period results in an average basis hedge of $0.91 per MMBtu less than the Henry Hub Index. In the Mid-Continent, we have hedged basis associated with approximately 17 Bcf of our anticipated natural gas production from the Stiles/Britt Ranch area for the period January 2012 through December 2012 at an average of $0.55 per MMBtu less than the Henry Hub Index.

The price we receive for our Gulf Coast oil production, excluding NGLs, typically averages about 105-110% of the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains, excluding NGLs, is currently averaging about $15-$17 per barrel below the WTI price. Oil production from our Mid-Continent properties, excluding NGLs, typically averages 90-95% of the WTI price. Crude oil from our operations in Malaysia typically sells at a slight discount to Tapis, or about 110-115% of WTI. Crude oil from our operations in China typically sells at $10-$15 per barrel greater than the WTI price.

Accounting for Hedging Activities. We do not designate price risk management activities as accounting hedges. Because hedges not designated for hedge accounting are accounted for on a mark-to-market basis with changes in fair value reported in current earnings, we have in the past experienced, and are likely in the future to experience, significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of December 31, 2011, we had net derivative assets of $137 million, of which 52% was measured based upon our valuation model (i.e. Black-Scholes), and, as such, are classified as a Level 3 fair value measurement. We value these contracts using a model that considers various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments. We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties. Please see "— Critical Accounting Policies and Estimates — *Commodity Derivative Activities*" below and Note 4, "Derivative Financial Instruments," and Note 7, "Fair Value Measurements," to our consolidated financial statements in Item 8 of this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments as described above under "— Contractual Obligations."

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Described below are the most significant policies we apply in preparing our financial statements, some of which are subject to alternative treatments under generally accepted accounting principles. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with the Audit Committee of our Board of Directors. See "— Results of Operations" above and Note 1, "Organization and Summary of Significant Accounting Policies," to our consolidated financial statements in Item 8 of this report for a discussion of additional accounting policies and estimates we make.

For discussion purposes, we have divided our significant policies into four categories. Set forth below is an overview of each of our significant accounting policies by category.

- ***We account for our oil and gas activities under the full cost method.*** This method of accounting requires the following significant estimates:
  - quantity of our proved oil and gas reserves;
  - costs withheld from amortization; and
  - future costs to develop and abandon our oil and gas properties.
- ***Accounting for business combinations*** *requires estimates and assumptions* regarding the fair value of the assets and liabilities of the acquired company.
- ***Accounting for commodity derivative activities*** *requires estimates and assumptions* regarding the fair value of derivative positions.
- ***Stock-based compensation cost*** *requires estimates and assumptions* regarding the grant date fair value of awards, the determination of which requires significant estimates and subjective judgments.

Oil and Gas Activities. Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available — successful efforts and full cost. The most significant differences between these two methods are the treatment of exploration costs and the manner in which the carrying value of oil and gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed, while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials, costs in effect at year-end and a 10% discount rate.

On December 31, 2008, the SEC issued *"Modernization of Oil and Gas Reporting"* (Final Rule). The Final Rule adopted revisions to the SEC's oil and gas reporting disclosure requirements and was effective for annual reports on Forms 10-K for years ending on or after December 31, 2009. On January 6, 2010, the FASB issued Accounting Standards Update No. 2010-03, *"Oil and Gas Reserve Estimation and Disclosures"* (ASU 2010-03), which aligned the oil and gas reserve estimation and disclosure requirements of FASB Accounting Standards Codification Topic 932, *"Extractive Industries — Oil and Gas"* (Topic 932), with the requirements in the SEC's Final Rule.

We adopted the Final Rule and ASU 2010-03 effective December 31, 2009. The following critical accounting policies and estimates discussions reflect the new rules unless stated otherwise. See "New Accounting Requirements" below for a full discussion.

Full Cost Method. We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized into cost centers (the amortization base) that are established on a country-by-country basis. Such amounts include the costs of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that are estimated to directly relate to our oil and gas activities. Interest costs related to unproved properties also are capitalized. Although some of these costs will ultimately result in no additional reserves, we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. Costs associated with production and general corporate activities are expensed in the period incurred. The capitalized costs of our oil and gas properties, plus an estimate of our future development costs, are amortized on a unit-of-production method based on our estimate of total proved reserves. Amortization is calculated separately on a country-by-country basis. Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas activities.

Proved Oil and Gas Reserves. Our engineering estimates of proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling limitation. Proved oil and gas reserves are the estimated quantities of oil and gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs based on the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials and under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and gas prices, operating costs and expected performance from a given reservoir also will result in future revisions to the amount of our estimated proved reserves. All reserve information in this report is based on estimates prepared by our petroleum engineering staff.

Depreciation, Depletion and Amortization. Estimated proved oil and gas reserves are a significant component of our calculation of DD&A expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test writedown. To change our domestic DD&A rate by $0.10 per Mcfe for the year ended December 31, 2011 would have required a change in the estimate of our domestic proved reserves of approximately 4%, or 145 Bcfe. To change our Malaysia DD&A rate by $0.10 per Mcfe for the year ended December 31, 2011 would have required a change in the estimate of our proved reserves in Malaysia of approximately 3%, or 4 Bcfe. Since production from our China operations is immaterial, any change in the DD&A rate as a result of changes in our proved reserves in China would not have materially affected our consolidated results of operations.

Full Cost Ceiling Limitation. Under the full cost method, we are subject to quarterly calculations of a "ceiling" or limitation on the amount of costs associated with our oil and gas properties that can be capitalized on our balance sheet. If net capitalized costs exceed the applicable cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, it would reduce earnings and stockholders' equity in the period of occurrence and result in lower DD&A expense in future periods. The ceiling limitation is applied separately for each country in which we have oil and gas properties. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The ceiling value of oil and gas reserves is calculated based on the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials, and costs in effect as of the last day of the quarter. The full cost ceiling test impairment calculation also takes into consideration the effects of hedging contracts that are designated for hedge accounting, if any.

At December 31, 2011, the ceiling value of our oil and gas reserves was calculated based on the unweighted average first-day-of-the-month commodity prices for the prior twelve months of $4.12 per MMBtu for natural gas and $96.13 per barrel for oil, adjusted for market differentials. Using these prices, the ceiling exceeded the net capitalized costs of our domestic oil and gas properties by approximately $1.3 billion (net of tax) at December 31, 2011. Holding all other factors constant, if the applicable unweighted average first-day-of-the-month commodity prices for the prior twelve months for both oil and gas were to decline approximately 10% from prices used at December 31, 2011, the excess of our domestic cost center ceiling over our capitalized costs would be reduced by approximately 65%.

At December 31, 2011, the Malaysia and China cost center ceilings exceeded the net capitalized costs of oil and gas properties by approximately $220 million and $390 million, respectively, net of tax. Holding all other factors constant, it is possible that we could experience a ceiling test writedown in Malaysia and China if the applicable unweighted average first-day-of-the-month oil price declined approximately 30% and 50%, respectively, from prices used at December 31, 2011.

At March 31, 2009, prior to our adoption of the Final Rule and ASU 2010-03, the ceiling value of our reserves was calculated based upon quoted period-end market prices of $3.63 per MMBtu for natural gas and $49.65 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties at March 31, 2009 exceeded the ceiling amount by approximately $1.3 billion ($854 million, after-tax), resulting in a ceiling test writedown.

Given the fluctuation of oil and gas prices, it is reasonably possible that the estimated discounted future net cash flows from our proved reserves will change in the near term. If the unweighted average first-day-of-the-month commodity prices for the prior twelve months decline, or if we have downward revisions to our estimated proved reserves, it is possible that additional writedowns of our oil and gas properties could occur in the future.

Costs Withheld From Amortization. Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage and seismic data, wells currently being drilled and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed quarterly for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base to the extent a reduction in value has occurred or a charge is made against earnings if the costs were incurred in a country for which a reserve base has not been established. If a reserve base for a country in which we are conducting operations has not yet been established, an impairment requiring a charge to earnings may be indicated through evaluation of drilling results, relinquishing drilling rights or other information.

In addition, a portion of the incurred (if not previously included in the amortization base) and future estimated development costs associated with qualifying major development projects may be temporarily excluded from amortization. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and estimated future development costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2011, we had a total of approximately $2.0 billion of costs excluded from the amortization base of our respective full cost pools. The application of the full cost ceiling test at December 31, 2011 resulted in an excess of the cost center ceilings over the carrying value of our oil and gas properties for each full cost pool. Holding all other factors constant, inclusion of approximately 75% of our domestic unevaluated property costs in the amortization base would not have resulted in a ceiling test writedown. Including all of our Malaysian unevaluated property costs in our Malaysia amortization base would not have resulted in a ceiling test writedown. At December 31, 2011, there were no costs withheld from the amortization base in China.

Future Development and Abandonment Costs. Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, market demand for equipment, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and abandonment costs on an annual basis, or more frequently if an event occurs or circumstances change that would affect our assumptions and estimates.

The accounting guidance for future abandonment costs requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Holding all other factors constant, if our estimate of future development and abandonment costs is revised upward, earnings would decrease due to higher DD&A expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense. To change our domestic DD&A rate by $0.10 per Mcfe for the year ended December 31, 2011 would have required a change in the estimate of our domestic future development and abandonment costs of approximately 10%, or $324 million. To change our Malaysia DD&A rate by $0.10 per Mcfe for the year ended December 31, 2011 would have required a change in the estimate of our future development and abandonment costs in Malaysia of approximately 15%, or $16 million. Since production from our China operations is immaterial, any change in the DD&A rate as a result of changes in the estimate of our future development and abandonment costs in China would not have materially affected our consolidated results of operations.

Allocation of Purchase Price in Business Combinations. As part of our growth strategy, we monitor and screen for potential acquisitions of oil and gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and gas reserves and unproved properties. To the extent the consideration paid exceeds the fair value of the net assets acquired, we are required to record the excess as an asset called goodwill. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain. The value allocated to recoverable oil and gas reserves and unproved properties is subject to the cost center ceiling as described under "— *Full Cost Ceiling Limitation*" above. The accounting for business combinations changed effective January 1, 2009 and established how a purchaser recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The standard also sets forth guidance related to the recognition, measurement and disclosure related to goodwill acquired in a business combination or gains associated with a bargain purchase transaction. The standard applies prospectively to business combinations for which the acquisition date is on or after December 31, 2008. We adopted the standard effective January 1, 2009. Since adoption of the standard, the assets we have acquired have not met the requirements to be accounted for as a business combination.

Commodity Derivative Activities. We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. We generally hedge a substantial, but varying, portion of our anticipated oil and gas production for the next 12-24 months. In the case of acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. We do not use derivative instruments for trading purposes. Under accounting rules, we may elect to designate those derivatives that qualify for hedge accounting as cash flow hedges against the price that we will receive for our future oil and gas production. Since late 2005, we have not designated future price risk management activities as accounting hedges. Because derivative contracts not designated for hedge accounting are accounted for on a mark-to-market basis, we are likely to experience significant non-cash volatility in our reported earnings during periods of commodity price volatility. Derivative assets and liabilities with the same counterparty and subject to contractual terms which provide for net settlement are reported on a net basis on our consolidated balance sheet.

In determining the amounts to be recorded for our open hedge contracts, we are required to estimate the fair value of the derivative. Our valuation models for derivative contracts are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The calculation of the fair value of our option contracts requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the hedge agreements and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differences and interest rates. We periodically validate our valuations using independent third-party quotations.

The determination of the fair values of derivative instruments incorporates various factors which include not only the impact of our non-performance risk on our liabilities but also the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests). We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties.

Stock-Based Compensation. We apply a fair value-based method of accounting for stock-based compensation which requires recognition in the financial statements of the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. For equity-based compensation awards, compensation expense is based on the fair value on the date of grant or modification and is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and a lattice-based model for our performance and market-based restricted stock. Additionally, in 2011, we granted cash-settled restricted units that are accounted for under the liability method which require Newfield to recognize the fair value of each award based on the underlying share price at the end of each period. See Note 10, "Stock-Based Compensation," to our consolidated financial statements in Item 8 of this report for a full discussion of our stock-based compensation.

New Accounting Requirements

In April 2009, the FASB issued additional guidance regarding fair value measurements and impairments of securities which made fair value measurements more consistent with fair value principles, enhanced consistency in financial reporting by increasing the frequency of fair value disclosures, and provided greater clarity and consistency in accounting for and presenting impairment losses on securities. The additional guidance was effective for interim and annual periods ending after June 15, 2009. We adopted the provisions for the period ended March 31, 2009. The adoption did not have a material impact on our financial position or results of operations.

In May 2009, the FASB established general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the guidance was based on the same principles as those that previously existed. This guidance was effective for interim or annual periods ending after June 15, 2009. Our adoption of these provisions beginning with the period ended June 30, 2009 did not have an impact on our financial position or results of operations.

On December 31, 2008, the SEC issued the "*Modernization of Oil and Gas Reporting*" (Final Rule). The Final Rule adopted revisions to the SEC's oil and gas reporting disclosure requirements and was effective for annual reports on Form 10-K for years ending on or after December 31, 2009. The revisions were intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments were also designed to modernize the oil and gas disclosure requirements to align them with current practices and changes in technology.

On January 6, 2010, the FASB issued Accounting Standards Update No. 2010-03, *"Oil and Gas Reserve Estimation and Disclosures"* (ASU 2010-03), which aligned the FASB's oil and gas reserve estimation and disclosure requirements with the requirements in the SEC's Final Rule. We adopted the Final Rule and ASU 2010-03 effective December 31, 2009 as a change in accounting principle that is inseparable from a change in accounting estimate. Such a change was accounted for prospectively under the authoritative accounting guidance. Comparative disclosures applying the new rules for periods before the adoption of ASU 2010-03 and the Final Rule were not required.

Our adoption of ASU 2010-03 and the Final Rule on December 31, 2009 impacted our financial statements and other disclosures in our annual report on Form 10-K for the years ended December 31, 2011, 2010 and 2009, as follows:

- All oil and gas reserves volumes presented as of and for the years ended December 31, 2011, 2010 and 2009 were prepared using the updated reserves rules and are not on a basis comparable with the prior period. This change in comparability occurred because we estimated our proved reserves at December 31, 2011, 2010 and 2009 using the updated reserves rules, which require use of the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials, and permits the use of reliable technologies to support reserve estimates. Under the previous reserve estimation rules, which are no longer in effect, our net proved oil and gas reserves would have been calculated using end of period oil and gas prices.
- Our full-cost ceiling test calculations at December 31, 2011, 2010 and 2009 used discounted cash flow models for our estimated proved reserves, which were calculated using the updated reserves rules.
- We historically have applied a policy of using our year-end proved reserves to calculate our fourth quarter depletion rate. As a result, the estimate of proved reserves for determining our depletion rate and resulting expense for the fourth quarter of 2009 and subsequent quarters is not on a basis comparable to the prior quarters or the prior years.

On April 20, 2010, the FASB issued Accounting Standards Update No. 2010-14, *"Accounting for Extractive Industries — Oil and Gas"* (ASU 2010-14), which aligned the oil and gas financial accounting and reporting requirements prescribed by FASB Accounting Standards Codification Topic 932, *"Extractive Industries — Oil and Gas"* (Topic 932) with the requirements in the SEC's Final Rule. The adoption of ASU 2010-14 did not have a material impact on our financial position or results of operations.

In January 2010, the FASB issued additional disclosure requirements related to fair value measurements. The guidance requires disclosure of transfers of assets and liabilities between Level 1 and Level 2 in the fair value measurement hierarchy, including the reasons for the transfers and disclosure of major purchases, sales, issuances, and settlements on a gross basis in the reconciliation of the assets and liabilities measured under Level 3 of the fair value measurement hierarchy. The guidance was effective for interim and annual periods beginning after December 15, 2009, except for the Level 3 reconciliation disclosures, which were effective for interim and annual periods beginning after December 15, 2010. We adopted the provisions for the quarter ended March 31, 2010, except for the Level 3 reconciliation disclosures, which we adopted for the quarter ended March 31, 2011. Adopting the disclosure requirements did not have a material impact on our financial position or results of operations.

In May 2011, the FASB issued additional guidance regarding fair value measurement and disclosure requirements. The most significant change will require us, for Level 3 fair value measurements, to disclose quantitative information about unobservable inputs used, a description of the valuation processes used, and a qualitative discussion about the sensitivity of the measurements. The guidance is effective for interim and annual periods beginning on or after December 15, 2011. We do not expect adoption of the additional fair value measurement and disclosure requirements to have a material impact on our financial position or results of operations.

In June 2011, the FASB issued guidance impacting the presentation of comprehensive income. The guidance eliminates the current option to report components of other comprehensive income in the statement of changes in equity. The guidance is intended to provide a more consistent method of presenting non-owner transactions that affect an entity's equity. The guidance is retrospective and is effective for interim and annual periods beginning on or after December 15, 2011. We elected early adoption of the provision for the year ended December 31, 2011. Adopting the reporting requirements did not have a material impact on our financial position or results of operations.

In December 2011, the FASB issued guidance regarding the disclosure of offsetting assets and liabilities. The guidance will require disclosure of gross information and net information about instruments and transactions eligible for offset arrangement. The guidance is effective for interim and annual periods beginning on or after January 1, 2013. We do not expect adoption of the additional disclosures about offsetting assets and liabilities to have a material impact on our financial position or results of operations.

Regulation

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, local and international regulations. An overview of these regulations is set forth in Items 1 and 2, *"Business and Properties* — Regulation." We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Please see the discussion under the caption *"We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business,"* in Item 1A of this report.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

We are exposed to market risk from changes in oil and gas prices, interest rates and foreign currency exchange rates as discussed below.

Oil and Gas Prices

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months to reduce our exposure to fluctuations in oil and gas prices. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While the use of hedging arrangements limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions also involves the risk that the counterparties, which generally are financial institutions, will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. For a further discussion of our hedging activities, see the information under the caption "Oil and Gas Hedging" in Item 7 of this report and the discussion and tables in Note 4, "Derivative Financial Instruments," to our consolidated financial statements in Item 8 of this report, which is incorporated herein by reference.

Interest Rates

At December 31, 2011, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Revolving credit facility	$ —	$86
5¾% Senior Notes due 2022	750	—
6⅝% Senior Subordinated Notes due 2014	325	—
6⅝% Senior Subordinated Notes due 2016	550	—
7⅛% Senior Subordinated Notes due 2018	600	—
6⅞% Senior Subordinated Notes due 2020	695	—
Total debt	$2,920	$86

We consider our interest rate exposure to be minimal because approximately 97% of our obligations were at fixed rates. Our variable rate debt is currently at interest rates of 2% or less. For a further discussion of our debt instruments, see the discussion and tables in Note 8, "Debt," to our consolidated financial statements in Item 8 of this report, which is incorporated herein by reference.

Foreign Currency Exchange Rates

The functional currency for all of our foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country's functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at December 31, 2011.

Item 8. ***Financial Statements and Supplementary Data***

NEWFIELD EXPLORATION COMPANY

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CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our company's management, including the Chief Executive Officer and the Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our 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 our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our 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.

Based on our evaluation under the framework in *Internal Control — Integrated Framework,* the management of our company concluded that our internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

Lee K. Boothby
President and Chief Executive Officer

Terry W. Rathert
Executive Vice President and Chief Financial Officer

Houston, Texas
February 27, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Newfield Exploration Company

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of net income, of comprehensive income, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Newfield Exploration Company and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated 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 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 opinions.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it estimates the quantities of oil and gas reserves in 2009 due to the adoption of Accounting Standards Update No. 2010-03, *Oil and Gas Reserve Estimation and Disclosures*.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2012

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEET
(In millions, except share data)

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 76	$ 39
Accounts receivable	407	354
Inventories	90	79
Derivative assets	129	197
Other current assets	73	62
Total current assets	775	731
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,965 and $1,658 were excluded from amortization at December 31, 2011 and 2010, respectively)	14,526	12,399
Less — accumulated depreciation, depletion and amortization	(6,506)	(5,791)
Total property and equipment, net	8,020	6,608
Derivative assets	61	39
Long-term investments	52	48
Deferred taxes	28	29
Other assets	55	39
Total assets	$ 8,991	$ 7,494
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 112	$ 92
Accrued liabilities	687	670
Advances from joint owners	45	51
Asset retirement obligations	10	11
Derivative liabilities	50	53
Deferred taxes	28	51
Total current liabilities	932	928
Other liabilities	44	56
Derivative liabilities	3	46
Long-term debt	3,006	2,304
Asset retirement obligations	135	97
Deferred taxes	951	720
Total long-term liabilities	4,139	3,223
Commitments and contingencies (Note 13)	—	—
Stockholders' equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)	—	—
Common stock ($0.01 par value, 200,000,000 shares authorized at December 31, 2011 and 2010; 136,379,381 and 135,910,641 shares issued at December 31, 2011 and 2010, respectively)	1	1
Additional paid-in capital	1,495	1,450
Treasury stock (at cost, 1,694,623 and 1,664,538 shares at December 31, 2011 and 2010, respectively)	(50)	(41)
Accumulated other comprehensive loss	(10)	(12)
Retained earnings	2,484	1,945
Total stockholders' equity	3,920	3,343
Total liabilities and stockholders' equity	$ 8,991	$ 7,494

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF NET INCOME
(In millions, except per share data)

	Year Ended December 31,		
	2011	2010	2009
Oil and gas revenues	$2,471	$1,883	$ 1,338
Operating expenses:			
Lease operating	453	326	259
Production and other taxes	330	126	63
Depreciation, depletion and amortization	767	644	587
General and administrative	185	156	144
Ceiling test and other impairments	—	7	1,344
Other	—	10	8
Total operating expenses	1,735	1,269	2,405
Income (loss) from operations	736	614	(1,067)
Other income (expenses):			
Interest expense	(175)	(156)	(126)
Capitalized interest	82	58	51
Commodity derivative income	195	316	252
Other	2	(3)	5
Total other income	104	215	182
Income (loss) before income taxes	840	829	(885)
Income tax provision (benefit):			
Current	93	59	48
Deferred	208	247	(391)
Total income tax provision (benefit)	301	306	(343)
Net income (loss)	$ 539	$ 523	$ (542)
Earnings (loss) per share			
Basic	$ 4.03	$ 3.97	$ (4.18)
Diluted	$ 3.99	$ 3.91	$ (4.18)
Weighted-average number of shares outstanding for basic earnings (loss) per share	134	132	130
Weighted-average number of shares outstanding for diluted earnings (loss) per share	135	134	130

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2011	2010	2009
Net income (loss)	$539	$523	$(542)
Other comprehensive income (loss):			
Unrealized gain on investments, net of tax of ($1) for each of the years ended December 31, 2011 and 2009	3	—	2
Realized loss on post-retirement benefits, net of tax of $1 for the year ended December 31, 2009	—	—	(2)
Unrealized loss on post-retirement benefits, net of tax	(1)	(1)	—
Other comprehensive income (loss), net of tax	2	(1)	—
Comprehensive income (loss)	$541	$522	$(542)

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In millions)

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
Balance, December 31, 2008	134.0	$ 1	(1.9)	$(32)	$1,335	$1,964	$(11)	$3,257
Issuances of common stock	0.5	—			9			9
Stock-based compensation					45			45
Treasury stock, net			0.4	(1)	—			(1)
Net loss						(542)		(542)
Other comprehensive income (loss), net of tax							—	—
Balance, December 31, 2009	134.5	1	(1.5)	(33)	1,389	1,422	(11)	2,768
Issuances of common stock	1.4	—			34			34
Stock-based compensation					33			33
Treasury stock, net			(0.2)	(8)	(6)			(14)
Net income						523		523
Other comprehensive loss, net of tax							(1)	(1)
Balance, December 31, 2010	135.9	1	(1.7)	(41)	1,450	1,945	(12)	3,343
Issuances of common stock	0.5	—			13			13
Stock-based compensation					37			37
Treasury stock, net			—	(9)	(5)			(14)
Net income						539		539
Other comprehensive income, net of tax							2	2
Balance, December 31, 2011	136.4	$ 1	(1.7)	$(50)	$1,495	$2,484	$(10)	$3,920

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	$ 539	$ 523	$ (542)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	767	644	587
Deferred tax provision (benefit)	208	247	(391)
Stock-based compensation	29	22	28
Commodity derivative income	(195)	(316)	(252)
Cash receipts on derivative settlements, net	195	456	883
Ceiling test and other impairments	—	7	1,344
Other non-cash charges	6	7	3
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(24)	(15)	36
(Increase) decrease in inventories	(16)	3	(3)
(Increase) decrease in other current assets	(12)	65	(78)
(Increase) decrease in other assets	(7)	(22)	4
Increase (decrease) in accounts payable and accrued liabilities	120	11	(23)
Decrease in advances from joint owners	(6)	—	(22)
Increase (decrease) in other liabilities	(15)	(2)	4
Net cash provided by operating activities	1,589	1,630	1,578
Cash flows from investing activities:			
Additions to oil and gas properties	(2,311)	(1,635)	(1,392)
Acquisitions of oil and gas properties	(304)	(313)	(9)
Proceeds from sales of oil and gas properties	406	12	33
Additions to furniture, fixtures and equipment	(29)	(23)	(8)
Redemptions of investments	2	8	20
Net cash used in investing activities	(2,236)	(1,951)	(1,356)
Cash flows from financing activities:			
Proceeds from borrowings under credit arrangements	3,958	1,483	1,040
Repayments of borrowings under credit arrangements	(4,007)	(1,732)	(1,216)
Proceeds from issuance of senior notes	750	—	—
Proceeds from issuance of senior subordinated notes	—	694	—
Debt issue costs	(16)	(8)	—
Repayment of senior notes	—	(175)	—
Proceeds from issuances of common stock	13	34	9
Purchases of treasury stock, net	(14)	(14)	(1)
Net cash provided by (used in) financing activities	684	282	(168)
Increase (decrease) in cash and cash equivalents	37	(39)	54
Cash and cash equivalents, beginning of period	39	78	24
Cash and cash equivalents, end of period	$ 76	$ 39	$ 78

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. Our principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and onshore Texas. Internationally, we focus on offshore oil developments in Malaysia and China.

Our financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. We proportionately consolidate our interests in oil and gas exploration and production ventures and partnerships in accordance with industry practice. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to "Newfield," "we," "us" or "our" are to Newfield Exploration Company and its subsidiaries.

Dependence on Oil and Gas Prices

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for oil and gas. Historically, the energy markets have been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil or gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital and on the quantities of oil and gas reserves that we can economically produce.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting period and the reported amounts of proved oil and gas reserves. Actual results could differ from these estimates. Our most significant financial estimates are associated with our estimated proved oil and gas reserves and the fair value of our derivative positions.

Reclassifications

Certain reclassifications have been made to prior years' reported amounts in order to conform to the current year presentation. These reclassifications did not impact our net income, stockholders' equity or cash flows.

Revenue Recognition

Substantially all of our oil and gas production is sold to a variety of purchasers under short-term contracts (less than 12 months) and, most recently, long-term contracts in the Uinta Basin, at market sensitive prices. We record revenue when we deliver our production to the customer and collectability is reasonably assured. Revenues from the production of oil and gas on properties in which we have joint ownership are recorded under the sales method. Differences between these sales and our entitled share of production are not significant.

Foreign Currency

The functional currency for all of our foreign operations is the U.S. dollar. Gains and losses incurred on currency transactions in other than a country's functional currency are recorded under the caption "Other income (expenses) — Other" on our consolidated statement of net income.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with a maturity of three months or less when acquired and are stated at cost, which approximates fair value. We invest cash in excess of near-term capital and operating requirements in U.S. Treasury Notes, Eurodollar time deposits and money market funds, which are classified as cash and cash equivalents on our consolidated balance sheet.

Investments

Investments consist primarily of debt and equity securities, as well as auction rate securities, a majority of which are classified as "available-for-sale" and stated at fair value. Accordingly, unrealized gains and losses and the related deferred income tax effects are excluded from earnings and reported as a separate component within the consolidated statement of comprehensive income. Realized gains or losses are computed based on specific identification of the securities sold. We regularly assess our investments for impairment and consider any impairment to be other than temporary if we intend to sell the security, it is more likely than not that we will be required to sell the security, or we do not expect to recover our cost of the security. We realized interest income and net gains on our investment securities in 2011, 2010 and 2009 of $2 million, $1 million and $2 million, respectively.

Allowance for Doubtful Accounts

We routinely assess the recoverability of all material trade and other receivables to determine their collectability. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, our oil and gas receivables are collected within 45 to 60 days of production. We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated.

Inventories

Inventories primarily consist of tubular goods and well equipment held for use in our oil and gas operations and oil produced in our operations offshore Malaysia and China but not sold. Inventories are carried at the lower of cost or market. Substantially all of the crude oil from our operations offshore Malaysia and China is produced into FPSOs and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 239,000 barrels and 277,000 barrels of crude oil valued at cost of $19 million and $15 million at December 31, 2011 and 2010, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depletion expense.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis. We capitalized $113 million, $79 million and $72 million of internal costs in 2011, 2010 and 2009, respectively. Interest expense related to unproved properties is also capitalized into oil and gas properties.

Proceeds from the sale of oil and gas properties are applied to reduce the costs in the applicable cost center unless the reduction would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized.

Capitalized costs and estimated future development costs are amortized on a unit-of-production method based on proved reserves associated with the applicable cost center. For each cost center, the net capitalized costs of oil and gas properties are limited to the lower of the unamortized cost or the cost center ceiling. For the years ended December 31, 2011, 2010 and 2009, a particular cost center ceiling is equal to the sum of:

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using oil and gas reserve estimation requirements, which require use of the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus
- the lower of cost or estimated fair value of properties not included in the costs being amortized, if any; less
- related income tax effects.

Prior to September 30, 2009, the present value (10% per annum discount rate) of estimated future net revenues from proved reserves was calculated using the end of period quoted market prices for oil and gas.

If net capitalized costs of oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, a ceiling test writedown reduces earnings and stockholders' equity in the period of occurrence and, holding other factors constant, results in lower depreciation, depletion and amortization expense in future periods.

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil and gas prices decrease significantly for a prolonged period of time or if we have substantial downward revisions in our estimated proved reserves. At December 31, 2011, the ceiling value of our reserves was calculated based upon the unweighted average first-day-of-the-month commodity prices for the prior twelve months of $4.12 per MMBtu for natural gas and $96.13 per barrel for oil, adjusted for market differentials. Using these prices, the cost center ceilings with respect to our properties in the U.S., Malaysia and China exceeded the net capitalized costs of the respective properties. As such, no ceiling test writedowns were required at December 31, 2011.

At December 31, 2010, the ceiling value of our reserves was calculated based upon the unweighted average first-day-of-the-month commodity prices for the prior twelve months of $4.38 per MMBtu for natural gas and $79.42 per barrel for oil, adjusted for market differentials. Using these prices, the cost center ceilings with respect to our properties in the U.S., Malaysia and China exceeded the net capitalized costs of the respective properties. As such, no ceiling test writedowns were required at December 31, 2010.

During the first quarter of 2009, natural gas prices decreased significantly as compared to prices in effect at December 31, 2008. At March 31, 2009, the ceiling value of our reserves was calculated based upon quoted period-end market prices of $3.63 per MMBtu for natural gas and $49.65 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties at March 31, 2009 exceeded the ceiling amount and, as a result, we recorded a charge of $1.3 billion ($854 million, after-tax) during the first quarter of 2009.

See Note 3, "Oil and Gas Assets," for a detailed discussion regarding our acquisition and sales transactions during 2011, 2010 and 2009.

Other Property and Equipment

Furniture, fixtures and equipment are recorded at cost and are depreciated using the straight-line method over their estimated useful lives, which range from three to seven years.

Accounting for Asset Retirement Obligations

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, we record a liability (an asset retirement obligation or ARO) on our consolidated balance sheet and capitalize the present value of the asset retirement cost in oil and gas properties in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation assuming the normal operation of the asset, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis within the related full cost pool. Both the accretion and the depreciation are included in depreciation, depletion and amortization expense on our consolidated statement of net income.

The change in our ARO for the three years ended December 31, 2011 is set forth below (in millions):

Balance at January 1, 2009	$ 81
Accretion expense	6
Additions	11
Revisions	7
Settlements	(13)
Balance at December 31, 2009	92
Accretion expense	8
Additions	21
Revisions	(8)
Settlements	(5)
Balance at December 31, 2010	108
Accretion expense	10
Additions	33
Revisions	3
Settlements	(9)
Balance at December 31, 2011	145
Less: Current portion of ARO at December 31, 2011	(10)
Total long-term ARO at December 31, 2011	$135

Income Taxes

We use the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax regulations existing at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in our financial statements. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

As of December 31, 2011, we did not have a liability for uncertain tax positions and as such we had not accrued related interest or penalties. The tax years 2008-2011 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

Stock-Based Compensation

We apply a fair value-based method of accounting for stock-based compensation. For equity-based compensation awards, compensation expense is based on the fair value on the date of grant or modification and is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and a lattice-based model for our performance and market-based restricted stock and restricted stock units. Additionally in 2011, we granted cash-settled restricted units that are accounted for under the liability method which require Newfield to recognize the fair value of each award based on the underlying share price at the end of each period. See Note 10, "Stock-Based Compensation," for a full discussion of our stock-based compensation.

Concentration of Credit Risk

We operate a substantial portion of our oil and gas properties. As the operator of a property, we make full payment for costs associated with the property and seek reimbursement from the other working interest owners in the property for their share of those costs. Our joint interest partners consist primarily of independent oil and gas producers. If the oil and gas exploration and production industry in general was adversely affected, the ability of our joint interest partners to reimburse us could be adversely affected.

The purchasers of our oil and gas production consist primarily of independent marketers, major oil and gas companies, refiners and gas pipeline companies. We perform credit evaluations of the purchasers of our production and monitor their financial condition on an ongoing basis. Based on our evaluations and monitoring, we obtain cash escrows, letters of credit or parental guarantees from some purchasers. Historically, we have sold our oil and gas production to several purchasers.

All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. The counterparties for all of our hedging transactions have an "investment grade" credit rating. We monitor the credit ratings of our hedging counterparties on an ongoing basis. Although we have entered into hedging contracts with multiple counterparties to mitigate our exposure to any individual counterparty, if any of our counterparties were to default on its obligations to us under the hedging contracts or seek bankruptcy protection, it could have a material adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future production being subject to commodity price changes. In addition, in poor economic environments and tight financial markets, the risk of a counterparty default is heightened and fewer counterparties may participate in hedging transactions, which could result in greater concentration of our exposure to any one counterparty or a larger percentage of our future production being subject to commodity price changes. At December 31, 2011, Barclays Bank PLC, Morgan Stanley Capital Group Inc., JPMorgan Chase Bank, N.A., Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to 86% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

Major Customers

Sales of oil and gas production to Royal Dutch Shell plc and Tesoro Corporation accounted for 12% and 11%, respectively, of our consolidated revenues in 2011. No single customer accounted for 10% or more of our sales of oil and gas production during 2010. During 2009, sales of our oil and gas production to Big West Oil LLC accounted for 16% of our consolidated revenues. We believe that the loss of Royal Dutch Shell plc would not have a material adverse effect on us because alternative purchasers are readily available. An extended loss of Tesoro Corporation, Big West Oil LLC, or any of our other large purchasers of our Monument Butte field oil production, could have a material adverse effect on us because there are limited purchasers of the black and yellow wax crude oil, which we produce from this field. Due to the higher paraffin content of this production, it must remain heated during shipping so it cannot be transported in conventional pipelines, and there is limited refining capacity for it in the vicinity of our production. In poor economic environments and tight financial markets, there is an increased risk that the current purchasers of our production may fail to satisfy their obligations to us under our crude oil purchase contracts. We cannot guarantee that we will be able to continue to sell to these purchasers or that similar substitute arrangements could be made for sales of our black and yellow wax crude oil with other purchasers if desired.

Derivative Financial Instruments

We account for our derivative activities by applying authoritative accounting and reporting guidance, which requires that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. All of the derivative instruments that we utilize are to manage the price risk attributable to our expected oil and gas production. We have elected not to designate price risk management activities as accounting hedges under the accounting guidance, and, accordingly, account for them using the mark-to-market accounting method. Under this method, the changes in contract values are reported currently in earnings. We also have utilized derivatives to manage our exposure to variable interest rates.

The related cash flow impact of our derivative activities are reflected as cash flows from operating activities. See Note 4, "Derivative Financial Instruments," for a more detailed discussion of our derivative activities.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) as well as unrealized gains and losses on investments and changes in post-retirement benefits, all recorded net of tax. As of December 31, 2011, accumulated other comprehensive loss consisted of an $8 million unrealized loss on investments and a $2 million unrealized loss on post-retirement benefits. As of December 31, 2010, accumulated other comprehensive loss consisted of an $11 million unrealized loss on investments and a $1 million unrealized loss on post-retirement benefits.

New Accounting Requirements

In April 2009, the FASB issued additional guidance regarding fair value measurements and impairments of securities which made fair value measurements more consistent with fair value principles, enhanced consistency in financial reporting by increasing the frequency of fair value disclosures, and provided greater clarity and consistency in accounting for and presenting impairment losses on securities. The additional guidance was effective for interim and annual periods ending after June 15, 2009. We adopted the provisions for the period ended March 31, 2009. The adoption did not have a material impact on our financial position or results of operations.

In May 2009, the FASB established general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the guidance was based on the same principles as those that previously existed. This guidance was effective for interim or annual periods ending after June 15, 2009. Our adoption of these provisions beginning with the period ended June 30, 2009 did not have an impact on our financial position or results of operations.

On December 31, 2008, the Securities and Exchange Commission (SEC) issued the "*Modernization of Oil and Gas Reporting*" (Final Rule). The Final Rule adopted revisions to the SEC's oil and gas reporting disclosure requirements and was effective for annual reports on Form 10-K for years ending on or after December 31, 2009. The revisions were intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments were also designed to modernize the oil and gas disclosure requirements to align them with current practices and changes in technology.

On January 6, 2010, the FASB issued Accounting Standards Update No. 2010-03, *"Oil and Gas Reserve Estimation and Disclosures"* (ASU 2010-03), which aligned the FASB's oil and gas reserve estimation and disclosure requirements with the requirements in the SEC's Final Rule. We adopted the Final Rule and ASU 2010-03 effective December 31, 2009 as a change in accounting principle that is inseparable from a change in accounting estimate. Such a change was accounted for prospectively under the authoritative accounting guidance. Comparative disclosures applying the new rules for periods before the adoption of ASU 2010-03 and the Final Rule were not required.

Our adoption of ASU 2010-03 and the Final Rule on December 31, 2009 impacted our financial statements and other disclosures in our annual report on Form 10-K for the years ended December 31, 2011, 2010 and 2009, as follows:

- All oil and gas reserves volumes presented as of and for the years ended December 31, 2011, 2010 and 2009 were prepared using the updated reserves rules and are not on a basis comparable with the prior period. This change in comparability occurred because we estimated our proved reserves at December 31, 2011, 2010 and 2009 using the updated reserves rules, which require use of the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials, and permits the use of reliable technologies to support reserve estimates. Under the previous reserve estimation rules, which are no longer in effect, our net proved oil and gas reserves would have been calculated using end of period oil and gas prices.
- Our full-cost ceiling test calculations at December 31, 2011, 2010 and 2009 used discounted cash flow models for our estimated proved reserves, which were calculated using the updated reserves rules.
- We historically have applied a policy of using our year-end proved reserves to calculate our fourth quarter depletion rate. As a result, the estimate of proved reserves for determining our depletion rate and resulting expense for the fourth quarter of 2009 and subsequent quarters is not on a basis comparable to the first three quarters of 2009.

On April 20, 2010, the FASB issued Accounting Standards Update No. 2010-14, *"Accounting for Extractive Industries — Oil and Gas"* (ASU 2010-14), which aligned the oil and gas financial accounting and reporting requirements prescribed by FASB Accounting Standards Codification Topic 932, *"Extractive Industries — Oil and Gas"* (Topic 932) with the requirements in the SEC's Final Rule. The adoption of ASU 2010-14 did not have a material impact on our financial position or results of operations.

In January 2010, the FASB issued additional disclosure requirements related to fair value measurements. The guidance requires disclosure of transfers of assets and liabilities between Level 1 and Level 2 in the fair value measurement hierarchy, including the reasons for the transfers and disclosure of major purchases, sales, issuances, and settlements on a gross basis in the reconciliation of the assets and liabilities measured under Level 3 of the fair value measurement hierarchy. The guidance was effective for interim and annual periods beginning after December 15, 2009, except for the Level 3 reconciliation disclosures, which were effective for interim and annual periods beginning after December 15, 2010. We adopted the provisions for the quarter ended March 31, 2010, except for the Level 3 reconciliation disclosures, which we adopted for the quarter ended March 31, 2011. Adopting the disclosure requirements did not have a material impact on our financial position or results of operations.

In May 2011, the FASB issued additional guidance regarding fair value measurement and disclosure requirements. The most significant change will require us, for Level 3 fair value measurements, to disclose quantitative information about unobservable inputs used, a description of the valuation processes used, and a qualitative discussion about the sensitivity of the measurements. The guidance is effective for interim and annual periods beginning on or after December 15, 2011. We do not expect adoption of the additional fair value measurement and disclosure requirements to have a material impact on our financial position or results of operations.

In June 2011, the FASB issued guidance impacting the presentation of comprehensive income. The guidance eliminates the current option to report components of other comprehensive income in the statement of changes in stockholders' equity. The guidance is intended to provide a more consistent method of presenting non-owner transactions that affect an entity's equity. The guidance is retrospective and is effective for interim and annual periods beginning on or after December 15, 2011. We elected early adoption of the provision for the year ended December 31, 2011. Adopting the reporting requirements did not have a material impact on our financial position or results of operations.

In December 2011, the FASB issued guidance regarding the disclosure of offsetting assets and liabilities. The guidance will require disclosure of gross information and net information about instruments and transactions eligible for offset arrangement. The guidance is effective for interim and annual periods beginning on or after January 1, 2013. We do not expect adoption of the additional disclosures about offsetting assets and liabilities to have a material impact on our financial position or results of operations.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted-average number of shares of common stock (other than unvested restricted stock and restricted stock units) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted stock and restricted stock units (using the treasury stock method). Under the treasury stock method, the amount the employee must pay for exercising stock options, the amount of unrecognized compensation expense related to unvested stock-based compensation grants and the amount of excess tax benefits that would be recorded when the award becomes deductible are assumed to be used to repurchase shares. Please see Note 10, "Stock-Based Compensation."

The following is the calculation of basic and diluted weighted-average shares outstanding and EPS for each of the years in the three-year period ended December 31, 2011:

	2011	2010	2009
	(In millions, except per share data)		
Income (numerator):			
Net income (loss) — basic and diluted	$ 539	$ 523	$ (542)
Weighted-average shares (denominator):			
Weighted-average shares — basic	134	132	130
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period[(1)(2)]	1	2	—
Weighted-average shares — diluted	135	134	130
Earnings (loss) per share:			
Basic earnings (loss) per share	$4.03	$3.97	$(4.18)
Diluted earnings (loss) per share	$3.99	$3.91	$(4.18)

(1) The calculation of shares outstanding for diluted EPS for the years ended December 31, 2011 and 2010 does not include the effect of 1.4 million and 0.7 million, respectively, of unvested restricted stock or restricted stock units and stock options because to do so would be anti-dilutive.

(2) The effect of stock options and unvested restricted stock and restricted stock units outstanding has not been included in the calculation of shares outstanding for diluted EPS for the year ended December 31, 2009 as their effect would have been anti-dilutive. Had we recognized net income for that period, incremental shares attributable to the assumed exercise of outstanding options and the assumed vesting of unvested restricted stock and restricted stock units would have increased diluted weighted-average shares outstanding by two million shares for the year ended December 31, 2009.

3. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at:

	December 31, 2011	2010	2009
		(In millions)	
Oil and gas properties:			
Subject to amortization	$12,423	$10,627	$ 9,090
Not subject to amortization	1,965	1,658	1,223
Gross oil and gas properties	14,388	12,285	10,313
Accumulated depreciation, depletion and amortization	(6,436)	(5,730)	(5,108)
Net oil and gas properties	7,952	6,555	5,205
Other property and equipment	138	114	93
Accumulated depreciation and amortization	(70)	(61)	(51)
Net other property and equipment	68	53	42
Total property and equipment, net	$ 8,020	$ 6,608	$ 5,247

Oil and gas properties not subject to amortization represent investments in unproved properties and major development projects in which we own an interest. These unproved property costs include unevaluated leasehold acreage, geological and geophysical data costs associated with leasehold or drilling interests, costs associated with wells currently drilling and capitalized interest. We exclude these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. Unproved property costs are grouped by major prospect area where individual property costs are not significant and are assessed individually when individual costs are significant. Costs associated with wells in progress are transferred to the amortization base upon the determination of whether proved reserves can be assigned to the properties, which is generally based on drilling results. All other costs excluded from the amortization base are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the amortization base or a charge is made against earnings for international operations if a reserve base has not yet been established.

The following is a summary of our oil and gas properties not subject to amortization as of December 31, 2011. We believe that our evaluation activities related to substantially all of our conventional properties not subject to amortization will be completed within four years. Because of the size of our unconventional resource plays, the entire evaluation will take significantly longer than four years. At December 31, 2011, approximately 70% of oil and gas properties not subject to amortization were associated with our unconventional resource plays.

	Costs Incurred In				
	2011	2010	2009	2008 and Prior	Total
	(In millions)				
Acquisition costs	$338	$345	$132	$381	$1,196
Exploration costs	233	39	56	36	364
Development costs	84	32	16	47	179
Fee mineral interests	—	—	—	23	23
Capitalized interest	82	58	51	12	203
Total oil and gas properties not subject to amortization	$737	$474	$255	$499	$1,965

Maverick Basin Asset Acquisition

In February 2010, we acquired certain of TXCO Resources Inc.'s assets in the Maverick Basin of southwest Texas for approximately $205 million. In the acquisition, we obtained an interest in approximately 300,000 net acres, primarily in the Pearsall and Eagle Ford shale plays, as well as production of 1,500 barrels of oil equivalent per day. Our consolidated financial statements include the cash flows and results of operations for these assets subsequent to the acquisition date.

Uinta Basin Asset Acquisitions

In May 2011, we closed two transactions to acquire assets in the Uinta Basin of Utah for a total of approximately $303 million (includes $4 million in purchase price adjustments). The assets include approximately 65,000 net acres, which are largely undeveloped and located north of our Greater Monument Butte field.

Other Asset Acquisitions and Sales

During 2011, 2010 and 2009, we acquired various other oil and gas properties for approximately $1 million, $108 million and $9 million, respectively, and sold various other oil and gas properties for approximately $434 million, $12 million and $33 million, respectively.

The cash flows and results of operations for the assets included in a sale are included in our consolidated financial statements up to the date of sale. All of the proceeds associated with our asset sales were recorded as adjustments to our domestic full cost pool.

4. Derivative Financial Instruments:

Commodity Derivative Instruments

We utilize swap, floor, collar and three-way collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a floor contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price. We are not required to make any payment in connection with the settlement of a floor contract. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price, we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price. A three-way collar contract consists of a standard collar contract plus a put sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in us being entitled to a net payment equal to the difference between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional no cost collar while defraying the associated cost with the sale of the additional put.

All of our derivative contracts are carried at their fair value on our consolidated balance sheet under the captions “Derivative assets” and “Derivative liabilities.” Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors requires the use of an option-pricing model. Please see Note 7, “Fair Value Measurements.” We recognize all realized and unrealized gains and losses related to these contracts on a mark-to-market basis in our consolidated statement of net income under the caption “Commodity derivative income.” Settlements of derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

At December 31, 2011, we had outstanding contracts with respect to our future production that are not designated for hedge accounting as set forth in the tables below.

Natural Gas

Period and Type of Contract	Volume in MMMBtus	NYMEX Contract Price Per MMBtu: Swaps (Weighted Average)	Additional Put: Range	Additional Put: Weighted Average	Collars: Floors: Range	Collars: Floors: Weighted Average	Collars: Ceilings: Range	Collars: Ceilings: Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
January 2012 — March 2012									
Price swap contracts	5,460	$5.42	—	—	—	—	—	—	$ 13
3-Way collar contracts	22,750	—	$3.50-$4.50	$4.30	$5.00-$6.00	$5.59	$5.20-$7.10	$6.55	29
April 2012 — June 2012									
Price swap contracts	5,460	5.42	—	—	—	—	—	—	12
3-Way collar contracts	22,750	—	3.50-4.50	4.30	5.00-5.75	5.44	5.20-7.00	6.26	24
July 2012 — September 2012									
Price swap contracts	5,520	5.42	—	—	—	—	—	—	12
3-Way collar contracts	23,000	—	3.50-4.50	4.30	5.00-5.75	5.44	5.20-7.00	6.26	23
October 2012 — December 2012									
Price swap contracts	1,860	5.42	—	—	—	—	—	—	4
3-Way collar contracts	15,070	—	3.50-4.50	4.19	5.00-6.00	5.51	5.20-7.55	6.41	16
January 2013 — December 2013									
Price swap contracts	18,250	5.33	—	—	—	—	—	—	25
3-Way collar contracts	39,530	—	3.50-4.50	4.04	5.00-6.00	5.44	6.00- 7.55	6.48	36
									$194

Oil

Period and Type of Contract	Volume in MBbls	NYMEX Contract Price Per Bbl: Additional Put: Range	Additional Put: Weighted Average	Collars: Floors: Range	Collars: Floors: Weighted Average	Collars: Ceilings: Range	Collars: Ceilings: Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
January 2012 — March 2012								
3-Way collar contracts	3,185	$55.00-$90.00	$66.86	$75.00-$100.00	$82.96	$88.20-$137.80	$111.14	$ (8)
April 2012 — June 2012								
3-Way collar contracts	3,185	55.00-90.00	66.86	75.00-100.00	82.96	88.20-137.80	111.14	(12)
July 2012 — September 2012								
3-Way collar contracts	3,220	55.00-90.00	66.86	75.00-100.00	82.96	88.20-137.80	111.14	(12)
October 2012 — December 2012								
3-Way collar contracts	3,220	55.00-90.00	66.86	75.00-100.00	82.96	88.20-137.80	111.14	(12)
January 2013 — December 2013								
3-Way collar contracts	4,745	55.00	55.00	80.00	80.00	109.50-111.40	110.54	(3)
								$(47)

Basis Contracts

At December 31, 2011, we had natural gas basis contracts that are not designated for hedge accounting to lock in the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points in the Rocky Mountains and Mid-Continent, as set forth in the table below.

	Rocky Mountains		Mid-Continent		Estimated Fair Value Asset (Liability)
	Volume in MMMBtus	Weighted-Average Differential	Volume in MMMBtus	Weighted-Average Differential	(In millions)
January 2012 — March 2012	1,230	$(0.91)	4,550	$(0.55)	$ (3)
April 2012 — June 2012	1,230	(0.91)	4,550	(0.55)	(3)
July 2012 — September 2012	1,230	(0.91)	4,600	(0.55)	(2)
October 2012 — December 2012	1,230	(0.91)	4,600	(0.55)	(2)
					$(10)

Interest Rate Swap

We previously hedged $50 million principal amount of our $175 million 7⅝% Senior Notes due 2011 through an interest rate swap. The swap provided for us to pay variable and receive fixed payments. During the first half of 2010, we repurchased our outstanding 7⅝% Senior Notes due 2011 and received approximately $2 million upon the termination and settlement of the swap.

Additional Disclosures about Derivative Instruments and Hedging Activities

We had derivative financial instruments recorded in our balance sheet as assets (liabilities) at their respective estimated fair value, as set forth below.

Type of Contract	Balance Sheet Location	December 31, 2011	December 31, 2010
		(In millions)	
Derivatives not designated as hedging instruments:			
Natural gas contracts	Derivative assets — current	$133	$201
Oil contracts	Derivative assets — current	1	1
Basis contracts	Derivative assets — current	(5)	(5)
Natural gas contracts	Derivative assets — noncurrent	61	45
Basis contracts	Derivative assets — noncurrent	—	(6)
Oil contracts	Derivative liabilities — current	(45)	(53)
Basis contracts	Derivative liabilities — current	(5)	—
Natural gas contracts	Derivative liabilities — noncurrent	—	(4)
Oil contracts	Derivative liabilities — noncurrent	(3)	(42)
Total		$137	$137

The amount of gain (loss) recognized in income related to our derivative financial instruments was as follows:

Type of Contract	Location of Gain (Loss) Recognized in Income	Year Ended December 31, 2011	2010	2009
		(In millions)		
Derivatives not designated as hedging instruments:				
Realized gain on natural gas contracts	Commodity derivative income	$249	$ 290	$ 514
Realized gain (loss) on oil contracts	Commodity derivative income	(47)	141	343
Realized loss on basis contracts	Commodity derivative income	(7)	(5)	(1)
Total realized gain		195	426	856
Unrealized gain (loss) on natural gas contracts	Commodity derivative income	(48)	109	(127)
Unrealized gain (loss) on oil contracts	Commodity derivative income	47	(222)	(443)
Unrealized gain (loss) on basis contracts	Commodity derivative income	1	3	(34)
Total unrealized loss		—	(110)	(604)
Total gain on derivatives not designated as hedging instruments		195	316	252
Derivative designated as a fair value hedge:				
Interest rate swap	Interest Expense	—	—	1
Total		$195	$ 316	$ 253

The total realized gain on commodity derivatives for the years ended December 31, 2010 and 2009 differs from the net cash receipts on derivative settlements due to the recognition of option premiums associated with derivatives settled during the respective periods. There were no option premiums recognized during the year ended December 31, 2011.

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate derivative instruments with that counterparty. At December 31, 2011, Barclays Bank PLC, Morgan Stanley Capital Group Inc., JPMorgan Chase Bank, N.A., Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to approximately 86% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

The counterparties to the majority of our derivative instruments also are lenders under our credit facility. Our credit facility, senior notes, senior subordinated notes and substantially all of our derivative instruments contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

5. Accounts Receivable:

As of the indicated dates, our accounts receivable consisted of the following:

	December 31, 2011	December 31, 2010
	(In millions)	
Revenue	$301	$199
Joint interest	96	133
Other	11	23
Reserve for doubtful accounts	(1)	(1)
Total accounts receivable	$407	$354

6. Accrued Liabilities:

As of the indicated dates, our accrued liabilities consisted of the following:

	December 31, 2011	December 31, 2010
	(In millions)	
Revenue payable	$ 94	$ 69
Accrued capital costs	231	327
Accrued lease operating expenses	86	54
Employee incentive expense	61	59
Accrued interest on debt	52	41
Taxes payable	122	81
Other	41	39
Total accrued liabilities	$687	$670

7. Fair Value Measurements:

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The authoritative guidance requires disclosure of the framework for measuring fair value and requires that fair value measurements be classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps and certain investments.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Our valuation models for derivative contracts are primarily industry-standard models (i.e., Black-Scholes) that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our valuation methodology for investments is a discounted cash flow model that considers various inputs including: (a) the coupon rate specified under the debt instruments, (b) the current credit ratings of the underlying issuers, (c) collateral characteristics and (d) risk adjusted discount rates. Level 3 instruments primarily include derivative instruments, such as basis swaps, commodity options including, price collars, floors and three-way collars (as of December 31, 2011, our options were comprised of only three-way collars) and some financial investments. Although we utilize third-party broker quotes to assess the reasonableness of our prices and valuation techniques, we do not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value of Investments and Derivative Instruments

The following tables summarize the valuation of our investments and financial instrument assets (liabilities) by pricing levels:

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(In millions)		
As of December 31, 2010:				
Investments available-for-sale:				
Equity securities	$ 7	$ —	$ —	$ 7
Auction rate securities	—	—	30	30
Oil and gas derivative swap contracts	—	89	(11)	78
Oil and gas derivative option contracts	—	—	59	59
Total	$ 7	$ 89	$ 78	$174
As of December 31, 2011:				
Investments available-for-sale:				
Equity securities	$10	$ —	$ —	$ 10
Auction rate securities	—	—	32	32
Oil and gas derivative swap contracts	—	66	(10)	56
Oil and gas derivative option contracts	—	—	81	81
Total	$10	$ 66	$103	$179

The determination of the fair values above incorporates various factors, which include not only the impact of our non-performance risk on our liabilities but also the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), if any. We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties.

As of December 31, 2011, we continued to hold $32 million of auction rate securities maturing beginning in 2033 that are classified as a Level 3 fair value measurement. This amount reflects a decrease in the fair value of these investments of $13 million ($8 million net of tax), recorded under the caption "Accumulated other comprehensive loss" on our consolidated balance sheet. As of December 31, 2010, we held $30 million of auction rate securities, which reflected a decrease in the fair value of $17 million ($11 million net of tax). The debt instruments underlying our auction rate securities are mostly investment grade (rated BBB+ or better) and are guaranteed by the United States government or backed by private loan collateral. We do not believe the decrease in the fair value of these securities is permanent because we currently intend to hold these investments until the auction succeeds, the issuer calls the securities or the securities mature. Our current available borrowing capacity under our credit arrangements provides us the liquidity to continue to hold these securities.

The following tables set forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the indicated periods:

	Investments	Derivatives	Total
		(In millions)	
Balance at January 1, 2009	$ 59	$ 542	$ 601
Total realized or unrealized gains (losses):			
Included in earnings	—	(55)	(55)
Included in other comprehensive loss	2	—	2
Purchases, issuances and settlements	(21)	(328)	(349)
Transfers in and out of Level 3	—	—	—
Balance at December 31, 2009	$ 40	$ 159	$ 199
Change in unrealized gains included in earnings relating to investments and derivatives still held at December 31, 2009	$ —	$ (95)	$ (95)
Balance at January 1, 2010	$ 40	$ 159	$ 199
Total realized or unrealized gains (losses):			
Included in earnings	—	31	31
Included in other comprehensive loss	(2)	—	(2)
Purchases, issuances and settlements	(8)	(142)	(150)
Transfers in and out of Level 3	—	—	—
Balance at December 31, 2010	$ 30	$ 48	$ 78
Change in unrealized gains included in earnings relating to investments and derivatives still held at December 31, 2010	$ —	$ 53	$ 53
Balance at January 1, 2011	$ 30	$ 48	$ 78
Total realized or unrealized gains (losses):			
Included in earnings	—	87	87
Included in other comprehensive income	4	—	4
Purchases, issuances and settlements:			
Settlements	(2)	(64)	(66)
Transfers in and out of Level 3	—	—	—
Balance at December 31, 2011	$ 32	$ 71	$ 103
Change in unrealized gains included in earnings relating to investments and derivatives still held at December 31, 2011	$ —	$ 56	$ 56

Fair Value of Debt

The estimated fair value of our notes, based on quoted market prices as of the indicated dates, was as follows:

	December 31, 2011	December 31, 2010
	(In millions)	
5¾% Senior Notes due 2022	$808	$ —
6⅝% Senior Subordinated Notes due 2014	329	333
6⅝% Senior Subordinated Notes due 2016	568	568
7⅛% Senior Subordinated Notes due 2018	635	626
6⅞% Senior Subordinated Notes due 2020	745	733

Amounts outstanding under our credit arrangements at December 31, 2011 and 2010 are stated at cost, which approximates fair value. Please see Note 8, "Debt."

8. Debt:

As of the indicated dates, our debt consisted of the following:

	December 31, 2011	December 31, 2010
	(In millions)	
Senior unsecured debt:		
Revolving credit facility — LIBOR based loans	$ 85	$ 100
Money market lines of credit[1]	1	35
Total credit arrangements	86	135
5¾% Senior Notes due 2022	750	—
Total senior unsecured debt	836	135
6⅝% Senior Subordinated Notes due 2014	325	325
6⅝% Senior Subordinated Notes due 2016	550	550
7⅛% Senior Subordinated Notes due 2018	600	600
6⅞% Senior Subordinated Notes due 2020	695	694
Total long-term debt	$3,006	$2,304

(1) Because capacity under our credit facility was available to repay borrowings under our money market lines of credit as of the indicated dates, amounts outstanding under these obligations are classified as long-term.

Credit Arrangements

In June 2011, we entered into a new revolving credit facility that matures in June 2016. The terms of the credit facility provide for loan commitments of $1.25 billion from a syndicate of 13 financial institutions, led by JPMorgan Chase Bank, N.A., as agent. In September 2011, we entered into the first amendment to the credit facility, which allows us to issue senior notes or other debt instruments that are secured equally and ratably with the credit facility. As of December 31, 2011, the largest individual loan commitment by any lender was 13% of total commitments.

Loans under the credit facility bear interest, at our option, equal to (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank, N.A. or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points, plus a margin that is based on a grid of our debt rating (75 basis points per annum at December 31, 2011) or (b) the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (175 basis points per annum at December 31, 2011).

Under our credit facility, we pay commitment fees on available but undrawn amounts based on a grid of our debt rating (30 basis points per annum at December 31, 2011). We incurred aggregate commitment fees under our current and previous credit facilities of approximately $2 million, $2 million and $1 million for each of the years ended December 31, 2011, 2010 and 2009, respectively, which are recorded in interest expense on our consolidated statement of net income.

Our credit facility has restrictive financial covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0 and maintenance of a ratio of earnings before gain or loss on the disposition of assets, interest expense, income taxes and noncash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test writedowns, and goodwill impairments) to interest expense of at least 3.0 to 1.0. At December 31, 2011, we were in compliance with all of our debt covenants.

Letters of credit are subject to a fronting fee of 20 basis points and annual fees based on a grid of our debt rating (175 basis points at December 31, 2011). As of December 31, 2011, we had no letters of credit outstanding under our credit facility.

Subject to compliance with the restrictive covenants in our credit facility, we also have a total of $185 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions.

The credit facility includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; inaccuracy of representations and warranties in any material respect; a change of control; or certain other material adverse changes in our business. Our senior notes and senior subordinated notes also contain standard events of default. If any of the foregoing defaults were to occur, our lenders under the credit facility could terminate future lending commitments and our lenders under both the credit facility and our notes could declare the outstanding borrowings due and payable. In addition, our credit facility, senior notes, senior subordinated notes and substantially all of our hedging arrangements contain provisions that provide for cross defaults and acceleration of those debt and hedging instruments in certain situations.

Senior Notes

In September 2011, we sold $750 million of 5¾% Senior Notes due 2022 and received proceeds of $742 million (net of discount and offering costs). These notes were issued at 99.956% of par to yield 5¾%. We used the net proceeds to repay a portion of our then outstanding borrowings under our credit facility and money market lines of credit.

Interest on our senior notes is payable semi-annually. The notes are unsecured and unsubordinated obligations and rank equally with all of our other existing and future unsecured and unsubordinated obligations. We may redeem some or all of our senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indenture governing our senior notes contains covenants that may limit our ability to, among other things:

- incur debt secured by liens;
- enter into sale/leaseback transactions; and
- enter into merger or consolidation transactions.

The indenture also provides that if any of our subsidiaries guarantee any of our indebtedness at any time in the future, then we will cause our senior notes to be equally and ratably guaranteed by that subsidiary.

Senior Subordinated Notes

In January 2010, we issued $700 million aggregate principal amount of our 6⅞% Senior Subordinated Notes due 2020. We received net proceeds from the offering of $686 million.

Interest on our senior subordinated notes is payable semi-annually. The notes are unsecured senior subordinated obligations that rank junior in right of payment to all of our present and future senior indebtedness.

We may redeem some or all of our 6⅝% notes due 2014 and our 6⅝% notes due 2016 at any time, in each case, at a redemption price stated in the applicable indenture governing the notes.

We may redeem some or all of our 7⅛% notes due 2018 at any time on or after May 15, 2013 at a redemption price stated in the indenture governing the notes. Prior to May 15, 2013, we may redeem all, but not part, of these notes at a make-whole redemption price plus accrued and unpaid interest to the date of redemption.

We may redeem some or all of our 6⅞% notes due 2020 at any time on or after February 1, 2015 at a redemption price stated in the indenture governing the notes. Prior to February 1, 2015, we may redeem some or all of these notes at a make-whole redemption price. In addition, before February 1, 2013, we may redeem up to 35% of these notes with the net cash proceeds of certain sales of our common stock at 106.875% of the principal amount, plus accrued and unpaid interest to the date of redemption.

The indenture governing our senior subordinated notes may limit our ability under certain circumstances to, among other things:

- incur additional debt;
- make restricted payments;
- pay dividends on or redeem our capital stock;
- make certain investments;
- create liens;
- engage in transactions with affiliates; and
- engage in mergers, consolidations and sales and other dispositions of assets.

9. Income Taxes:

For the indicated periods, income (loss) before income taxes consisted of the following:

	For the Year Ended December 31,		
	2011	2010	2009
	(In millions)		
U.S.	$618	$658	$(1,033)
Foreign	222	171	148
Total income (loss) before income taxes	$840	$829	$ (885)

For the indicated periods, the total provision (benefit) for income taxes consisted of the following:

	For the Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Current taxes:			
U.S. federal	$ 17	$ (1)	$ 4
Foreign	76	60	44
Deferred taxes:			
U.S. federal	171	228	(352)
U.S. state	30	16	(28)
Foreign	7	3	(11)
Total provision (benefit) for income taxes	$301	$306	$(343)

The provision (benefit) for income taxes for each of the years in the three-year period ended December 31, 2011 was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	For the Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Amount computed using the statutory rate	$294	$290	$(310)
Increase (decrease) in taxes resulting from:			
State and local income taxes, net of federal effect	10	11	(18)
Net effect of different tax rates in non-U.S. jurisdictions	6	5	5
Valuation allowance	5	—	(24)
Other	(14)	—	4
Total provision (benefit) for income taxes	$301	$306	$(343)

As of the indicated dates, the components of our deferred tax asset and deferred tax liability were as follows:

	December 31, 2011			December 31, 2010		
	U.S.	Foreign	Total	U.S.	Foreign	Total
	(In millions)					
Deferred tax asset:						
Net operating loss carryforwards	$ 651	$ 17	$ 668	$ 661	$ 9	$ 670
Alternative minimum tax credit	102	—	102	85	—	85
Stock-based compensation	22	—	22	22	—	22
Marketable securities	5	—	5	6	—	6
Oil and gas properties	—	28	28	—	26	26
Valuation allowance	(5)	(6)	(11)	—	(6)	(6)
Other	9	—	9	25	—	25
Deferred tax asset	784	39	823	799	29	828
Deferred tax liability:						
Commodity derivatives	(50)	—	(50)	(51)	—	(51)
Oil and gas properties	(1,660)	(64)	(1,724)	(1,474)	(45)	(1,519)
Deferred tax liability	(1,710)	(64)	(1,774)	(1,525)	(45)	(1,570)
Net deferred tax liability	(926)	(25)	(951)	(726)	(16)	(742)
Less: Net current deferred tax liability	(28)	—	(28)	(51)	—	(51)
Net noncurrent deferred tax liability	$ (898)	$(25)	$ (923)	$ (675)	$(16)	$ (691)

As of December 31, 2011 and 2010, we had gross net operating loss (NOL) carryforwards of approximately $2 billion for federal income tax and $1 billion for state income tax purposes, which may be used in future years to offset taxable income. NOL carryforwards of $273 million are subject to annual limitations due to stock ownership changes. We currently estimate that we will not be able to utilize $127 million of our various gross state NOLs because we do not have sufficient estimated future taxable income in the appropriate jurisdiction. To the extent not utilized, the NOL carryforwards will begin to expire during the years 2019 through 2031.

As of December 31, 2011 and 2010, we had gross NOL carryforwards for international income tax purposes of approximately $48 million and $29 million, respectively. During the year ended December 31, 2011, we generated international NOL carryforwards of $31 million and utilized international NOLs of $12 million which were generated in 2010. Our international NOLs must be utilized during the term of the respective production sharing contract in the appropriate jurisdiction. In addition, as of December 31, 2011 and 2010, we had $17 million of international NOLs, which we currently estimate that we will not be able to utilize because we do not have sufficient estimated future taxable income in the appropriate jurisdictions. As a result, valuation allowances were established for these items in 2005 and 2006.

Utilization of NOL carryforwards is dependent upon generating sufficient future taxable income in the appropriate jurisdictions within the carryforward period. Estimates of future taxable income can be significantly affected by changes in oil and gas prices, estimates of the timing and amount of future production and estimates of future operating and capital costs. Therefore, no certainty exists that we will be able to fully utilize our existing NOL carryforwards.

The rollforward of our deferred tax asset valuation allowance is as follows:

	For the Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Balance at the beginning of the year	$ (6)	$ (6)	$(30)
Charged to provision for income taxes:			
Malaysia ceiling test writedown	—	—	24
U.S. state net operating loss carryforwards	(5)	—	—
Balance at the end of the year	$(11)	$ (6)	$ (6)

In 2011, we recorded a $5 million valuation allowance related to various NOLs which were generated in certain of the states where we conduct operations.

In 2009, we reversed the valuation allowance related to the deferred tax asset associated with our fourth quarter 2008 ceiling test writedown in Malaysia. The valuation allowance was released as a result of a substantial increase in our estimate of future taxable income in Malaysia due to increases in anticipated future crude oil prices.

U.S. deferred taxes have not been recorded with respect to foreign income of $39 million that is permanently reinvested internationally. We currently do not have any foreign tax credits available to reduce U.S. taxes on this income if it was repatriated.

10. Stock-Based Compensation:

On May 5, 2011, at our 2011 annual meeting of stockholders, our stockholders approved the Newfield Exploration Company 2011 Omnibus Stock Plan (the 2011 Omnibus Stock Plan), and our 2009 Omnibus Stock Plan and 2009 Non-Employee Director Restricted Stock Plan were terminated such that no new grants will be made under the previous plans. All stock-based compensation equity awards to employees and non-employee directors will be granted under the 2011 Omnibus Stock Plan. Outstanding awards under those previous plans were not impacted by the termination of those previous plans. The fair value of grants is determined utilizing the Black-Scholes option pricing model for stock options and a lattice-based model for our performance and market-based restricted stock and restricted stock units. In February 2011, we also granted cash-settled restricted stock units to employees that were not issued under any of our plans as they will be settled in cash upon vesting and are accounted for as liability awards.

We issue new shares of stock when stock options are exercised. Beginning in 2009, we began to primarily utilize treasury shares when restricted stock is issued or restricted stock units vest.

Shares available for grant under our 2011 Omnibus Stock Plan are reduced by 1.87 times the number of shares of restricted stock or restricted stock units awarded under the plan, and are reduced by 1 times the number of shares subject to stock options awarded under the plan. At December 31, 2011, we had approximately (1) 6.3 million additional shares available for issuance pursuant to our existing employee and director plans if all future employee awards under our 2011 Omnibus Stock Plan are stock options, or (2) 3.4 million additional shares available for issuance pursuant to our existing employee and director plans if all future employee awards under our 2011 Omnibus Stock Plan are restricted stock or restricted stock units. Thus far, the majority of the awards under our 2011 Omnibus Stock Plan have been granted as restricted stock unit awards.

As of the indicated dates, our stock-based compensation consisted of the following:

	For the Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Total stock-based compensation	$ 40	$ 33	$ 45
Capitalized in oil and gas properties	(11)	(11)	(17)
Net stock-based compensation expense	$ 29	$ 22	$ 28

The excess tax benefit realized from stock options exercised is recognized as a credit to additional paid-in capital and is calculated as the amount by which the tax deduction we receive exceeds the deferred tax asset associated with recorded stock-based compensation expense. We did not realize an excess tax benefit from stock-based compensation for 2011, 2010 or 2009 because we did not have sufficient taxable income to fully realize the deduction. At December 31, 2011, we had unrecognized net operating losses of $122 million related to stock-based compensation.

As of December 31, 2011, we had approximately $81 million of total unrecognized stock-based compensation expense related to unvested stock-based compensation awards. This compensation expense is expected to be recognized on a straight-line basis over the applicable remaining vesting period. The full amount is expected to be recognized within approximately five years.

Stock Options. We have granted stock options under several plans. Options generally expire ten years from the date of grant and become exercisable at the rate of 20% per year. The exercise price of options cannot be less than the fair market value per share of our common stock on the date of grant.

The following table provides information about stock option activity for the years ended December 31, 2011, 2010 and 2009:

	Number of Shares Underlying Options	Weighted Average Exercise Price per Share	Weighted Average Grant Date Fair Value per Share	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value[1]
	(In millions)			(In years)	(In millions)
Outstanding at December 31, 2008	3.5	$28.74		5.5	$ 3
Granted	—	—	$—		
Exercised	(0.5)	21.07			9
Forfeited	(0.1)	32.74			
Outstanding at December 31, 2009	2.9	29.82		4.7	56
Granted	—	—	—		
Exercised	(1.4)	24.34			46
Forfeited	—	—			
Outstanding at December 31, 2010	1.5	34.58		4.7	58
Granted	—	—	—		
Exercised	(0.4)	29.54			18
Forfeited	—	—			
Outstanding at December 31, 2011	1.1	$36.31		4.0	$ 7
Exercisable at December 31, 2011	0.9	$34.20		3.6	$ 7

(1) The intrinsic value of a stock option is the amount by which the market value of our common stock at the indicated date, or at the time of exercise, exceeds the exercise price of the option.

On December 31, 2011, the last reported sales price of our common stock on the New York Stock Exchange was $37.73 per share.

The following table summarizes information about stock options outstanding and exercisable at December 31, 2011:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Underlying Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price per Share	Number of Shares Underlying Options	Weighted Average Exercise Price per Share
	(In millions)	(In years)		(In millions)	
$15.01 to $17.50	0.1	0.7	$16.61	0.1	$16.61
17.51 to 22.50	0.1	1.1	18.73	0.1	18.73
22.51 to 27.50	0.1	2.2	24.77	0.1	24.77
27.51 to 35.00	0.3	3.0	31.08	0.3	31.08
35.01 to 41.72	—	—	—	—	—
41.73 to 48.45	0.5	6.1	48.45	0.3	48.45
	1.1	4.0	$36.31	0.9	$34.20

Restricted Stock. At December 31, 2011, our employees held an aggregate of 2.2 million shares of restricted stock and restricted stock units that primarily vest over a service period of three to five years. The vesting of these shares and units is dependent upon the employee's continued service with our company. In addition, at December 31, 2011, our employees held 0.3 million shares of restricted stock subject to performance-based vesting criteria (substantially all of which are considered market-based restricted stock under authoritative accounting guidance).

The following table provides information about restricted stock and restricted stock unit activity for the years ended December 31, 2011, 2010 and 2009:

	Service-Based Shares	Performance/ Market-Based Shares	Total Shares	Weighted Average Grant Date Fair Value per Share
	(In millions, except per share data)			
Non-vested shares outstanding at January 1, 2009	1.7	1.2	2.9	$34.58
Granted	1.1	—	1.1	24.03
Forfeited	(0.1)	(0.3)	(0.4)	26.84
Vested	(0.3)	(0.1)	(0.4)	36.07
Non-vested shares outstanding at December 31, 2009	2.4	0.8	3.2	31.60
Granted	0.6	0.1	0.7	52.20
Forfeited	(0.2)	(0.1)	(0.3)	33.09
Vested	(0.6)	(0.5)	(1.1)	32.78
Non-vested shares outstanding at December 31, 2010	2.2	0.3	2.5	36.84
Granted	1.0	0.1	1.1	64.35
Forfeited	(0.2)	—	(0.2)	44.79
Vested	(0.8)	(0.1)	(0.9)	34.86
Non-vested shares outstanding at December 31, 2011	2.2	0.3	2.5	$49.52

The total fair value of restricted stock and restricted stock units that vested during the years ended December 31, 2011, 2010 and 2009 was $32 million, $39 million and $15 million, respectively.

Cash-Settled Restricted Stock Units. During the first quarter of 2011, we granted cash-settled restricted stock units to employees that vest over three years. The value of the awards, and the associated stock-based compensation expense, is based on the Company's stock price. As of December 31, 2011, 132,065 cash-settled restricted stock units were outstanding.

Employee Stock Purchase Plan. Pursuant to our employee stock purchase plan, for each six month period beginning on January 1 or July 1 during the term of the plan, each eligible employee has the opportunity to purchase our common stock for a purchase price equal to 85% of the lesser of the fair market value of our common stock on the first day of the period or the last day of the period. No employee may purchase common stock under the plan valued at more than $25,000 in any calendar year. Employees of our foreign subsidiaries are not eligible to participate in the plan.

At our May 7, 2010 annual meeting, our stockholders approved the Newfield Exploration Company 2010 Employee Stock Purchase Plan. This plan replaced our 2001 Employee Stock Purchase Plan which was terminated on June 30, 2010. This plan became effective July 1, 2010 with one million shares of our common stock available for issuance.

During 2011, options to purchase 85,982 shares of our common stock were issued under our employee stock purchase plans. The weighted-average fair value of each option was $16.95 per share. The fair value of the options granted was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free weighted-average interest rate of 0.14%, an expected life of six months and weighted-average volatility of 32.21%. At December 31, 2011, 868,755 shares of our common stock remained available for issuance under the current plan.

During 2010, options to purchase 83,009 shares of our common stock at a weighted-average fair value of $13.23 per share were issued under the plan. The fair value of the options granted was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free weighted-average interest rate of 0.21%, an expected life of six months and weighted-average volatility of 44.64%.

During 2009, options to purchase 139,207 shares of our common stock at a weighted-average fair value of $8.95 per share were issued under the plan. The fair value of the options granted was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free weighted-average interest rate of 0.29%, an expected life of six months and weighted-average volatility of 80.49%.

11. Pension Plan Obligation:

As a result of our acquisition of EEX Corporation in November 2002, we assumed responsibility for a defined benefit pension plan for current and former employees of EEX and its subsidiaries. The plan was amended, effective March 31, 2003, to cease all future retirement benefit accruals. We filed for a standard termination with a proposed plan termination date of April 30, 2008. A favorable determination letter was received on March 16, 2009 from the Internal Revenue Service. During the second half of 2009, we completed the formal termination process and all participants received full payment of their obligation through an annuity purchase or a lump sum payment. Curtailment accounting was applied for year-end 2009 resulting in a charge of $3 million recorded to general and administrative expense associated with changes in the pension liability due to actual plan termination costs.

12. Employee Benefit Plans:

Post-Retirement Medical Plan

We sponsor a post-retirement medical plan that covers all retired employees until they reach age 65. At December 31, 2011, both our accumulated benefit obligation and our accrued benefit costs were $11 million. Our net periodic benefit cost was approximately $2 million for the year ended December 31, 2011 and approximately $1 million for each of the years ended December 31, 2010 and 2009.

The expected future benefit payments under our post-retirement medical plan for the next ten years are as follows (in millions):

2012 — 2016	$2
2017 — 2021	5

Annual Cash Incentive Compensation Plan

During 2010, our Board of Directors, with the recommendation of the Compensation & Management Development Committee approved a new annual cash incentive compensation plan for all employees (the 2011 Annual Incentive Plan). Under the 2011 Annual Incentive Plan, the Compensation & Management Development Committee determines the annual award pool for all employees based upon a number of factors including the Company's performance against stated performance goals and in comparison with peer companies in our industry. All employees are eligible if employed on October 1 and December 31 of the performance period. Beginning with the year ended December 31, 2010, our annual cash incentive compensation is paid in a single payment to employees during the first quarter after the end of the performance period.

Incentive compensation awards for periods prior to 2010 were made under our 2003 Incentive Compensation Plan. That plan provided for the creation of an award pool that was equal to 5% of our adjusted net income (as defined in the plan) and it was administered by the Compensation & Management Development Committee. Awards under the plan could have both a current and a long-term component with the long-term cash awards being paid in four annual installments consisting of 25% of the long-term award, plus interest.

Total incentive compensation expense for the years ended December 31, 2011, 2010 and 2009 was $39 million, $36 million and $28 million, respectively.

401(k) and Deferred Compensation Plans

We sponsor a 401(k) profit sharing plan under Section 401(k) of the Internal Revenue Code. This plan covers all of our employees other than employees of our foreign subsidiaries. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee's salary, subject to limitations imposed by the IRS. We also sponsor a highly compensated employee deferred compensation plan. This non-qualified plan allows an eligible employee to defer a portion of his or her salary or bonus on an annual basis. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee's salary, subject to limitations imposed by the plan. Our contribution with respect to each participant in the deferred compensation plan is reduced by the amount of contribution made by us to our 401(k) plan for that participant. Our combined contributions to these two plans for the years ended December 31, 2011, 2010 and 2009 totaled $8 million, $6 million and $5 million, respectively.

13. Commitments and Contingencies:

Lease Commitments

We have various commitments under non-cancellable operating lease agreements for office space and firm transportation. Future minimum payments required under these leases as of December 31, 2011 are as follows (in millions):

Year Ending December 31,	
2012	$ 84
2013	91
2014	93
2015	89
2016	85
Thereafter	290
Total minimum lease payments	$732

Rent expense with respect to our lease commitments for office space for the years ended December 31, 2011, 2010 and 2009 was $16 million, $11 million and $9 million, respectively.

Other Commitments

As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work-related commitments for, among other things, drilling wells, obtaining and processing seismic data, transportation of our production and fulfilling other related commitments. At December 31, 2011, these work-related commitments totaled $133 million, all of which were attributable to our international business.

We also have various commitments for drilling rigs and other equipment, as well as certain service contracts. The majority of these commitments are related to contracts for hydraulic well fracturing services and drilling rigs and payments under these contracts are accounted for as capital additions to our oil and gas properties. As of December 31, 2011, future payments under these agreements are approximately $256 million in 2012, $84 million in 2013, $11 million in 2014 and $3 million in 2015.

We have various oil and gas production volume delivery commitments that are related to our domestic operations. As of December 31, 2011, our delivery commitments through 2020 were as follows:

Year Ending December 31,	Natural Gas (MMMBtus)	Oil (MBbls)
2012	39,626	915
2013	—	6,235
2014	—	8,395
2015	—	8,395
2016	—	8,418
Thereafter	—	23,713
Total delivery commitments	39,626	56,071

Litigation

We have been named as a defendant in a number of lawsuits and are involved in various other disputes, all arising in the ordinary course of our business, such as (1) claims from royalty owners for disputed royalty payments, (2) commercial disputes, (3) personal injury claims and (4) property damage claims. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

14. Segment Information:

While we only have operations in the oil and gas exploration and production industry, we are organizationally structured along geographic operating segments. Our current operating segments are the United States, Malaysia, China and Other International. The accounting policies of each of our operating segments are the same as those described in Note 1, "Organization and Summary of Significant Accounting Policies."

The following tables provide the geographic operating segment information for the years ended December 31, 2011, 2010 and 2009. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Year Ended December 31, 2011:					
Oil and gas revenues	$1,742	$647	$ 82	$—	$2,471
Operating expenses:					
Lease operating	358	90	5	—	453
Production and other taxes	68	242	20	—	330
Depreciation, depletion and amortization	621	126	20	—	767
General and administrative	180	4	1	—	185
Allocated income tax	191	70	9	—	
Net income from oil and gas properties	$ 324	$115	$ 27	$—	
Total operating expenses					1,735
Income from operations					736
Interest expense, net of interest income, capitalized interest and other					(91)
Commodity derivative income					195
Income before income taxes					$ 840
Total assets	$7,861	$878	$252	$—	$8,991
Additions to long-lived assets	$2,230	$307	$ 57	$—	$2,594

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Year Ended December 31, 2010:					
Oil and gas revenues	$1,427	$399	$ 57	$—	$1,883
Operating expenses:					
Lease operating	264	56	6	—	326
Production and other taxes	44	73	9	—	126
Depreciation, depletion and amortization	515	110	16	3	644
General and administrative	150	5	1	—	156
Ceiling test and other impairments	7	—	—	—	7
Other	10	—	—	—	10
Allocated income tax (benefit)	162	59	6	(1)	
Net income (loss) from oil and gas properties	$ 275	$ 96	$ 19	$ (2)	
Total operating expenses					1,269
Income from operations					614
Interest expense, net of interest income, capitalized interest and other					(101)
Commodity derivative income					316
Income before income taxes					$ 829
Total assets	$6,650	$647	$197	$—	$7,494
Additions to long-lived assets	$1,834	$134	$ 39	$—	$2,007

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Year Ended December 31, 2009:					
Oil and gas revenues	$ 972	$321	$ 45	$—	$ 1,338
Operating expenses:					
Lease operating	203	51	5	—	259
Production and other taxes	33	25	5	—	63
Depreciation, depletion and amortization	463	111	13	—	587
General and administrative	139	4	1	—	144
Ceiling test and other impairments	1,344	—	—	—	1,344
Other	8	—	—	—	8
Allocated income tax (benefit)	(438)	49	5	—	
Net income (loss) from oil and gas properties	$ (780)	$ 81	$ 16	$—	
Total operating expenses					2,405
Loss from operations					(1,067)
Interest expense, net of interest income, capitalized interest and other					(70)
Commodity derivative income					252
Loss before income taxes					$ (885)
Total assets	$5,485	$591	$178	$—	$ 6,254
Additions to long-lived assets	$1,365	$101	$ 60	$—	$ 1,526

15. Supplemental Cash Flows Information:

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Cash Payments:			
Interest payments, net of interest capitalized of $82, $58 and $51 during 2011, 2010 and 2009, respectively	$ 79	$ 79	$ 74
Income tax payments	70	87	3
Non-cash items excluded from the statement of cash flows:			
(Increase) decrease in accrued capital expenditures	$ 90	$ (8)	$ 12
Increase in asset retirement costs	(33)	(13)	(19)

16. Related Party Transaction:

Susan G. Riggs, our Treasurer, is a minority owner of Huffco International L.L.C. (Huffco). In May 1997, before Ms. Riggs joined us, we acquired from Huffco an entity now known as Newfield China, LDC, the owner of a 12% interest in a three field unit located on Blocks 04/36 and 05/36 in Bohai Bay, offshore China. Huffco retained preferred shares of Newfield China that provide for an aggregate dividend equal to 10% of the excess of proceeds received by Newfield China from the sale of oil, gas and other minerals over all costs incurred with respect to exploration and production in Block 05/36, plus the cash purchase price we paid Huffco for Newfield China ($6 million). During 2011, 2010 and 2009, Newfield China paid $5 million, $4 million and $2 million, respectively, of dividends to Huffco on the preferred shares of Newfield China. Based on our estimate of the net present value of the proved reserves associated with Block 05/36, the indirect interest (through Huffco) in Newfield China's preferred shares held by Ms. Riggs had a net present value of approximately $240,000 at December 31, 2011.

17. Quarterly Results of Operations (Unaudited):

The results of operations by quarter for the indicated periods are as follows:

	2011 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil and gas revenues	$ 545	$ 621	$ 628	$ 677
Income from operations	178	200	178	180
Net income (loss)	(17)	219	269	68
Basic earnings (loss) per common share(1)	$(0.13)	$1.64	$2.00	$0.51
Diluted earnings (loss) per common share	$(0.13)	$1.62	$1.99	$0.51

	2010 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil and gas revenues	$ 458	$ 448	$ 449	$ 528
Income from operations	175	130	146	163
Net income	244	96	161	22
Basic earnings per common share(1)	$ 1.87	$0.73	$1.22	$0.17
Diluted earnings per common share	$ 1.84	$0.72	$1.20	$0.17

(1) The sum of the individual quarterly earnings (loss) per share may not agree with year-to-date earnings (loss) per share as each quarterly computation is based on the income or loss for that quarter and the weighted-average number of shares outstanding during that quarter.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES — UNAUDITED

Costs Incurred

Costs incurred for oil and gas property acquisitions, exploration and development for each of the years in the three-year period ended December 31, 2011 are as follows:

	Domestic	Malaysia	China	Total
		(In millions)		
2011:				
Property acquisitions:				
Unproved	$ 361	$ —	$—	$ 361
Proved	72	19	—	91
Exploration(1)	980	9	25	1,014
Development(2)	795	279	31	1,105
Total costs incurred(3)	$2,208	$307	$56	$2,571
2010:				
Property acquisitions:				
Unproved	$ 329	$ —	$—	$ 329
Proved	71	—	—	71
Exploration(1)	896	45	24	965
Development(2)	520	88	14	622
Total costs incurred(3)	$1,816	$133	$38	$1,987
2009:				
Property acquisitions:				
Unproved	$ 114	$ —	$—	$ 114
Proved	33	—	—	33
Exploration(1)	817	38	47	902
Development(2)	311	60	12	383
Total costs incurred(3)	$1,275	$ 98	$59	$1,432

(1) Includes $237 million, $248 million and $181 million of domestic costs for non-exploitation activities for 2011, 2010 and 2009, respectively; $9 million, $27 million and $21 million of Malaysia costs for non-exploitation activities for 2011, 2010 and 2009, respectively; and $25 million, $24 million and $47 million of China costs for non-exploitation activities for 2011, 2010 and 2009, respectively.

(2) Includes $33 million, $13 million and $19 million for 2011, 2010 and 2009, respectively, of asset retirement costs.

(3) Other items impacting the capitalized costs of our oil and gas properties which are not included in total costs incurred are as follows:

	2011	2010	2009
		(In millions)	
Proceeds from property sales — Domestic	$434	$12	$ 33
Insurance settlement proceeds — Domestic	—	—	7
Ceiling test writedown — Domestic	—	—	1,344
	$434	$12	$1,384

Capitalized Costs

Capitalized costs for our oil and gas producing activities consisted of the following at the end of each of the years in the three-year period ended December 31, 2011:

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
December 31, 2011:					
Proved properties	$11,404	$ 985	$213	$—	$12,602
Unproved properties	1,622	89	75	—	1,786
	13,026	1,074	288	—	14,388
Accumulated depreciation, depletion and amortization	(5,876)	(486)	(74)	—	(6,436)
Net capitalized costs	$ 7,150	$ 588	$214	$—	$ 7,952
December 31, 2010:					
Proved properties	$ 9,903	$ 673	$166	$—	$10,742
Unproved properties	1,383	94	66	—	1,543
	11,286	767	232	—	12,285
Accumulated depreciation, depletion and amortization	(5,313)	(362)	(55)	—	(5,730)
Net capitalized costs	$ 5,973	$ 405	$177	$—	$ 6,555
December 31, 2009:					
Proved properties	$ 8,500	$ 561	$121	$—	$ 9,182
Unproved properties	982	73	73	3	1,131
	9,482	634	194	3	10,313
Accumulated depreciation, depletion and amortization	(4,814)	(255)	(39)	—	(5,108)
Net capitalized costs	$ 4,668	$ 379	$155	$ 3	$ 5,205

Reserves

Users of this information should be aware that the process of estimating quantities of proved and proved developed oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir also may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates may occur from time to time.

SEC and FASB Rule-Making Activities. On December 31, 2008, the SEC issued the Final Rule adopting revisions to the SEC's oil and gas reporting disclosure requirements. In addition, in January 2010, the FASB issued ASU 2010-03, which aligned the FASB's oil and gas reserve estimation and disclosure requirements with the requirements in the SEC's Final Rule. See Note 1, "Organization and Summary of Significant Accounting Policies — *New Accounting Requirements*."

We adopted the Final Rule and ASU 2010-03 effective December 31, 2009 as a change in accounting principle that is inseparable from a change in accounting estimate. Such a change was accounted for prospectively under the authoritative accounting guidance. Comparative disclosures applying the new rules for periods before the adoption of ASU 2010-03 and the Final Rule were not required.

Our adoption of ASU 2010-03 and the Final Rule on December 31, 2009 impacted our financial statements and other disclosures in our annual report on Form 10-K for the year ended December 31, 2011, as follows:

- All oil and gas reserves volumes presented as of and for the years ended December 31, 2011, 2010 and 2009 were prepared using the updated reserves rules and are not on a basis comparable with the prior period. This change in comparability occurred because we estimated our proved reserves at December 31, 2011, 2010 and 2009 using the updated reserves rules, which require use of the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials, and permits the use of reliable technologies to support reserve estimates. Under the previous reserve estimation rules, which are no longer in effect, our net proved oil and gas reserves would have been calculated using end of period oil and gas prices.
- Our full-cost ceiling test calculations at December 31, 2011, 2010 and 2009 used discounted cash flow models for our estimated proved reserves, which were calculated using the updated reserves rules.
- We historically have applied a policy of using our year-end proved reserves to calculate our fourth quarter depletion rate. As a result, the estimate of proved reserves for determining our depletion rate and resulting expense for the fourth quarter of 2009 and subsequent quarters is not on a basis comparable to the prior quarters or the prior year.

Reserves Estimates. All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. The preparation of our oil and gas reserves estimates is completed in accordance with our prescribed internal control procedures, which include verification of data input into reserves forecasting and economics evaluation software, as well as multi-discipline management reviews. The technical employee responsible for overseeing the preparation of the reserves estimates has a Bachelor of Science in Petroleum Engineering, with more than 30 years of experience (including 20 years of experience in reserve estimation). For additional information regarding our reserves estimation process, please see Items 1 and 2, "*Business and Properties* — Reserves."

Reserves Activity Overview. The following is a discussion of our proved reserves and reserve additions and revisions.

	Year Ended December 31,		
	2011	2010	2009
		(Bcfe)	
Proved Reserves:			
Beginning of year	3,712	3,616	2,950
Reserve additions	909	676	1,342
Reserve revisions	(288)	(289)	(384)
Sales	(122)	(3)	(35)
Production	(300)	(288)	(257)
End of year	3,911	3,712	3,616

Our proved natural gas reserves at year-end 2011 were 2.3 Tcf compared to 2.5 Tcf at year-end 2010 and 2.6 Tcf at year-end 2009. Our proved crude oil and condensate reserves at year-end 2011 were 263 million barrels compared to 204 million barrels at year-end 2010 and 169 million barrels at year-end 2009. Natural gas comprised about 60%, 67% and 72% of our proved reserves at year-end 2011, 2010 and 2009, respectively.

Reserve Additions and Revisions. During 2011, we added 621 Bcfe net proved reserves as a result of additions (extensions, discoveries, improved recovery and purchases of reserves in place) and revisions, as described below. We expect the majority of future reserve additions to be associated with infill drilling, extensions of current fields and new discoveries, as well as improved recovery operations and purchases of proved properties. The success of these operations will directly impact reserve additions or revisions in the future.

Additions. We added 857 Bcfe of proved reserves through discoveries, extensions and other additions, and 52 Bcfe through purchases. Drilling additions related primarily to activities in our resource plays in the Mid-Continent and Rocky Mountains. Of the drilling additions, 430 Bcfe or 72 million BOE were proved undeveloped additions in the Rocky Mountains, associated primarily with the Williston Basin and Monument Butte field. In addition, 16 million barrels of oil of proved developed reserves were added reflecting our continued focus on higher margin oil projects.

We added 676 Bcfe of proved reserves during 2010. Approximately 414 Bcfe of the additions resulted from successful development drilling, primarily in our Mid-Continent and Rocky Mountain divisions, where we added 322 Bcfe of proved undeveloped reserves primarily associated with our Woodford Shale, Williston Basin and Monument Butte fields. In addition, during 2010, extensions and other additions totaled 236 Bcfe, reflecting the shift in our investment strategy from natural gas to higher margin oil projects. We added 1,342 Bcfe of proved reserves during 2009, approximately 521 Bcfe of which were the result of successful development drilling in our Mid-Continent and Rocky Mountain business units. Domestic extensions, discoveries and other additions also included 693 Bcfe of additions resulting from the change in the SEC definition of proved reserves, expanding proved undeveloped reserve locations beyond one direct offset away from producing wells. These locations were primarily in the Woodford Shale and Monument Butte fields.

Revisions. Our total proved reserve revisions in 2011 were 288 Bcfe. Price-related and other revisions were negligible. Of proved undeveloped reserves, 87 Bcfe were reclassified to probable reserves as we directed capital to higher margin oil drilling and the locations associated with these reserves moved outside of a five-year development horizon. Negative performance revisions in 2011 were 198 Bcfe, which included (i) well performance as efforts to extend the Monument Butte-Green River section to the northwest encountered higher than expected natural gas production, (ii) the timing of waterflood response recognition in Monument Butte, (iii) wellbore failures in gas reservoirs along the Gulf Coast and (iv) offset well interference in older vertical natural gas wells in the Mid-Continent, which were adversely impacted by new horizontal well completions.

Our revisions in 2010 include the reclassification of approximately 315 Bcfe of proved undeveloped reserves (nearly all Mid-Continent natural gas reserves) to probable reserves because a slower pace of development activity placed them beyond the five-year development horizon. This change reflected a shift in our investment strategy toward oil projects. Excluding this reclassification, our revisions were 26 Bcfe, consisting of positive price-related revisions of 56 Bcfe, partially offset by 30 Bcfe of performance-related revisions. Total revisions in 2009 were a negative 384 Bcfe, or 13% of the beginning of year reserve base. The revisions included a negative price revision of 259 Bcfe primarily related to our onshore natural gas plays, such as the Woodford Shale, and were primarily proved undeveloped reserves. The remaining 125 Bcfe of revisions in 2009 were negative performance revisions and were principally proved developed producing reserve revisions.

Sales. In 2011, we sold 122 Bcfe of proved reserves associated with non-strategic properties. In 2010, sales of reserves were negligible. During 2009, we sold approximately 35 Bcfe of reserves associated with our domestic operations.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES — UNAUDITED — (Continued)

Estimated Net Quantities of Proved Oil and Gas Reserves

The following table sets forth our total net proved reserves and our total net proved developed reserves as of December 31, 2008, 2009, 2010 and 2011 and the changes in our total net proved reserves during the three-year period ended December 31, 2011:

	Oil, Condensate and Natural Gas Liquids (MMBbls)				Natural Gas (Bcf)			Total Natural Gas Equivalents (Bcfe)			
	Domestic	Malaysia(1)	China(1)	Total	Domestic	Malaysia(1)	Total	Domestic	Malaysia(1)	China(1)	Total
Proved developed and undeveloped reserves as of:											
December 31, 2008	111	22	7	140	2,110	—	2,110	2,774	135	41	2,950
Revisions of previous estimates	(3)	—	(1)	(4)	(358)	—	(358)	(376)	—	(8)	(384)
Extensions, discoveries and other additions(2)	38	8	2	48	1,045	—	1,045	1,270	48	13	1,331
Purchases of properties	1	—	—	1	6	—	6	11	—	—	11
Sales of properties	(2)	—	—	(2)	(26)	—	(26)	(35)	—	—	(35)
Production	(8)	(5)	(1)	(14)	(172)	—	(172)	(220)	(32)	(5)	(257)
December 31, 2009	137	25	7	169	2,605	—	2,605	3,424	151	41	3,616
Revisions of previous estimates	(5)	1	—	(4)	(268)	—	(268)	(298)	9	—	(289)
Extensions, discoveries and other additions	46	7	—	53	338	—	338	614	40	—	654
Purchases of properties	2	—	—	2	9	—	9	22	—	—	22
Sales of properties	—	—	—	—	—	—	—	(3)	—	—	(3)
Production	(10)	(5)	(1)	(16)	(192)	—	(192)	(252)	(31)	(5)	(288)
December 31, 2010	170	28	6	204	2,492	—	2,492	3,507	169	36	3,712
Revisions of previous estimates	(17)	(2)	—	(19)	(175)	—	(175)	(276)	(11)	(1)	(288)
Extensions, discoveries and other additions	78	3	15	96	276	4	280	746	23	88	857
Purchases of properties	7	—	—	7	9	—	9	52	—	—	52
Sales of properties	(5)	—	—	(5)	(91)	—	(91)	(122)	—	—	(122)
Production	(13)	(6)	(1)	(20)	(182)	—	(182)	(259)	(36)	(5)	(300)
December 31, 2011	220	23	20	263	2,329	4	2,333	3,648	145	118	3,911
Proved developed reserves as of:											
December 31, 2008	65	12	5	82	1,336	—	1,336	1,727	72	28	1,827
December 31, 2009	70	10	5	85	1,397	—	1,397	1,820	60	28	1,908
December 31, 2010	90	15	5	110	1,505	—	1,505	2,045	91	28	2,164
December 31, 2011	98	17	5	120	1,405	4	1,409	1,989	109	31	2,129

(1) All of our reserves in Malaysia and China are associated with production sharing contracts and are calculated using the economic interest method.

(2) Effective December 31, 2009, the SEC changed the definition of proved reserves, expanding proved undeveloped reserve locations beyond one direct offset away from producing wells.

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

The following information was developed utilizing procedures prescribed by FASB Accounting Standards Codification Topic 932, *Extractive Industries — Oil and Gas* (Topic 932). The information is based on estimates prepared by our petroleum engineering staff. The "standardized measure of discounted future net cash flows" should not be viewed as representative of the current value of our proved oil and gas reserves. It and the other information contained in the following tables may be useful for certain comparative purposes, but should not be solely relied upon in evaluating us or our performance.

In reviewing the information that follows, we believe that the following factors should be taken into account:

- future costs and sales prices will probably differ from those required to be used in these calculations;
- actual production rates for future periods may vary significantly from the rates assumed in the calculations;
- a 10% discount rate may not be reasonable relative to risk inherent in realizing future net oil and gas revenues; and
- future net revenues may be subject to different rates of income taxation.

Under the standardized measure, future cash inflows were estimated by applying the prices used in estimating our proved oil and gas reserves to the year-end quantities of those reserves. Future cash inflows do not reflect the impact of open hedge positions. See Note 4, "Derivative Financial Instruments." Future cash inflows were reduced by estimated future development, abandonment and production costs based on year-end costs in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying year-end statutory tax rates to aggregate future pre-tax net cash flows reduced by the tax basis of the properties involved and tax carryforwards. The standardized measure is derived from using a discount rate of 10% a year to reflect the timing of future net cash flows relating to proved oil and gas reserves.

In general, management does not rely on the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible outcomes.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES — UNAUDITED — (Continued)

The standardized measure of discounted future net cash flows from our estimated proved oil and gas reserves is as follows:

	Domestic	Malaysia	China	Total
	(In millions)			
2011:				
Future cash inflows	$26,241	$ 2,751	$2,213	$31,205
Less related future:				
Production cost	(6,523)	(1,563)	(850)	(8,936)
Development and abandonment costs	(4,246)	(161)	(228)	(4,635)
Future net cash flows before income taxes	15,472	1,027	1,135	17,634
Future income tax expense	(4,344)	(210)	(268)	(4,822)
Future net cash flows before 10% discount	11,128	817	867	12,812
10% annual discount for estimating timing of cash flows	(6,404)	(125)	(302)	(6,831)
Standardized measure of discounted future net cash flows	$ 4,724	$ 692	$ 565	$ 5,981
2010:				
Future cash inflows	$20,694	$ 2,145	$ 461	$23,300
Less related future:				
Production cost	(4,360)	(1,056)	(171)	(5,587)
Development and abandonment costs	(3,089)	(199)	(23)	(3,311)
Future net cash flows before income taxes	13,245	890	267	14,402
Future income tax expense	(4,146)	(191)	(52)	(4,389)
Future net cash flows before 10% discount	9,099	699	215	10,013
10% annual discount for estimating timing of cash flows	(5,041)	(142)	(76)	(5,259)
Standardized measure of discounted future net cash flows	$ 4,058	$ 557	$ 139	$ 4,754
2009:				
Future cash inflows	$14,738	$ 1,594	$ 392	$16,724
Less related future:				
Production cost	(3,864)	(701)	(109)	(4,674)
Development and abandonment costs	(3,016)	(245)	(27)	(3,288)
Future net cash flows before income taxes	7,858	648	256	8,762
Future income tax expense	(1,879)	(109)	(52)	(2,040)
Future net cash flows before 10% discount	5,979	539	204	6,722
10% annual discount for estimating timing of cash flows	(3,645)	(133)	(80)	(3,858)
Standardized measure of discounted future net cash flows	$ 2,334	$ 406	$ 124	$ 2,864

Set forth in the table below is a summary of the changes in the standardized measure of discounted future net cash flows for our proved oil and gas reserves during each of the years in the three-year period ended December 31, 2011:

	Domestic	Malaysia	China	Total
		(In millions)		
2011:				
Beginning of the period	$ 4,058	$ 557	$ 139	$ 4,754
Revisions of previous estimates:				
Changes in prices and costs	728	191	83	1,002
Changes in quantities	(829)	(60)	(7)	(896)
Changes in future development costs	(31)	(110)	—	(141)
Development costs incurred during the period	499	188	13	700
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	1,366	101	497	1,964
Purchases and sales of reserves in place, net	(93)	—	—	(93)
Accretion of discount	591	71	17	679
Sales of oil and gas, net of production costs	(1,048)	(197)	(36)	(1,281)
Net change in income taxes	(222)	(26)	(141)	(389)
Production timing and other	(294)	(24)	—	(318)
Net increase	667	134	426	1,227
End of period	$ 4,725	$ 691	$ 565	$ 5,981
2010:				
Beginning of the period	$ 2,334	$ 406	$ 124	$ 2,864
Revisions of previous estimates:				
Changes in prices and costs	1,720	54	25	1,799
Changes in quantities	(372)	44	—	(328)
Changes in future development costs	119	(18)	(2)	99
Development costs incurred during the period	401	92	8	501
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	1,179	194	—	1,373
Purchases and sales of reserves in place, net	60	—	—	60
Accretion of discount	307	49	16	372
Sales of oil and gas, net of production costs	(810)	(187)	(32)	(1,029)
Net change in income taxes	(1,115)	(70)	(2)	(1,187)
Production timing and other	235	(7)	2	230
Net increase	1,724	151	15	1,890
End of period	$ 4,058	$ 557	$ 139	$ 4,754
2009:				
Beginning of the period	$ 2,545	$ 303	$ 81	$ 2,929
Revisions of previous estimates:				
Changes in prices and costs	(351)	142	55	(154)
Changes in quantities	(550)	(1)	(35)	(586)
Changes in future development costs	273	13	(8)	278
Development costs incurred during the period	303	51	9	363
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	572	99	50	721
Purchases and sales of reserves in place, net	(23)	—	—	(23)
Accretion of discount	336	33	9	378
Sales of oil and gas, net of production costs	(807)	(130)	(21)	(958)
Net change in income taxes	164	(68)	(19)	77
Production timing and other	(128)	(36)	3	(161)
Net increase (decrease)	(211)	103	43	(65)
End of period	$ 2,334	$ 406	$ 124	$ 2,864

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A. *Controls and Procedures*

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2011.

Management's Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm

The information required to be furnished pursuant to this item is set forth under the captions "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" in Item 8 of this report.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information appearing under the headings "Election of Directors," "Section 16(A) Beneficial Ownership Reporting Compliance," "Corporate Governance — Board of Directors," "Corporate Governance — Committees," "Corporate Governance — Audit Committee," "Corporate Governance — Nominating & Corporate Governance Committee" and "Stockholder Proposals for 2013 Annual Meeting and Director Nominations" in our proxy statement for our 2012 annual meeting of stockholders to be held on May 4, 2012 (the "2012 Proxy Statement") and the information set forth under the heading "Executive Officers of the Registrant" in this report are incorporated herein by reference.

Corporate Code of Business Conduct and Ethics

We have adopted a corporate code of business conduct and ethics for directors, officers (including our principal executive officer, principal financial officer and controller or principal accounting officer) and employees. Our corporate code includes a financial code of ethics applicable to our chief executive officer, chief financial officer and controller or chief accounting officer. Both of these codes are available under the "Corporate Governance — Overview" tab on our website at *www.newfield.com.*

We intend to satisfy the disclosure requirements of Item 5.05 of Form 8-K regarding any amendment to, or waiver from, a provision of the financial code of ethics that applies to our principal executive officer, principal financial officer, principal accounting officer or controller and relates to any element of the definition of code of ethics set forth in Item 406(b) of Regulation S-K by posting such information under the "Corporate Governance" tab of our website at *www.newfield.com.*

Corporate Governance Materials

We have adopted charters for each of the Audit Committee, the Compensation & Management Development Committee and the Nominating & Corporate Governance Committee of our Board of Directors and Corporate Governance Guidelines. Each of these documents is available under the "Corporate Governance — Overview" tab on our website at *www.newfield.com.*

Item 11. *Executive Compensation*

The information appearing in our 2012 Proxy Statement under the headings "Compensation & Management Development Committee Report" (which is furnished), "Executive Compensation," "Non-Employee Director Compensation" and "Compensation Committee Interlocks and Insider Participation" is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information appearing in our 2012 Proxy Statement under the headings "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information" is incorporated herein by reference.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

The information appearing in our 2012 Proxy Statement under the headings "Corporate Governance — Board of Directors," "Corporate Governance — Committees" and "Interests of Management and Others in Certain Transactions" is incorporated herein by reference.

Item 14. *Principal Accounting Fees and Services*

The information appearing in our 2012 Proxy Statement under the heading "Principal Accountant Fees and Services" is incorporated herein by reference.

Board of Directors

Lee K. Boothby (50)
Chairman, President and
Chief Executive Officer,
Newfield Exploration Company

Philip J. Burguieres (*) (***) (68)
Chairman and Chief Executive Officer,
EMC Holdings, LLC;
Vice Chairman, Houston Texans
(Lead Director)

Pamela J. Gardner (*) (***) (55)
Special Advisor to Jim Crane of the
Houston Astros (Former President,
Business Operations of the Houston Astros)

John Randolph Kemp III (*) (***) (67)
Chairman, Kosmos Energy;
Principal, The Kemp Company;
Retired President – Exploration Production,
Americas, Conoco, Inc.

J. Michael Lacey (**) (***) (66)
Retired Senior Vice President – Exploration
and Production, Devon Energy Corporation

Joseph H. Netherland (*) (***) (65)
Retired Chairman, President and Chief
Executive Officer, FMC Technologies, Inc.

Howard H. Newman (*) (64)
President and Chief Executive Officer,
Pine Brook Road Partners, LLC; (Former
Vice Chairman, Warburg Pincus LLC)

Thomas G. Ricks (**) (***) (58)
Chief Investment Officer,
H&S Ventures L.L.C.

Juanita F. Romans (**) (***) (61)
President, The Romans Group;
(Former Chief Executive Officer and
Central Market Leader,
Memorial Hermann – Texas Medical Center)

C.E. (Chuck) Shultz (**) (72)
Chairman and Chief Executive Officer,
Dauntless Energy Inc.

J. Terry Strange (**) (***) (68)
Retired Vice Chairman, KPMG, LLP

(*) Member of the Compensation and Management Development Committee

(**) Member of the Audit Committee

(***) Member of the Nominating and Corporate Governance Committee

Officers

Lee K. Boothby (50)
Chairman, President and
Chief Executive Officer

Gary D. Packer (49)
Executive Vice President and
Chief Operating Officer

Terry W. Rathert (59)
Executive Vice President and
Chief Financial Officer

W. Mark Blumenshine (53)
Vice President – Land

Stephen C. Campbell (43)
Vice President – Investor Relations

George T. Dunn (54)
Vice President – Mid-Continent

Daryll T. Howard (49)
Vice President – Rocky Mountains

John H. Jasek (42)
Vice President – Onshore Gulf Coast

Deanna L. Jones (43)
Vice President – Human Resources

John D. Marziotti (48)
General Counsel and Secretary

Lawrence S. Massaro (48)
Vice President – Corporate Development

James J. Metcalf (54)
Vice President – Drilling

Brian L. Rickmers (43)
Chief Commercial Officer,
Controller and Assistant Secretary

Susan G. Riggs (54)
Treasurer

William D. Schneider (60)
Vice President – Gulf of Mexico
& International

Michael D. Van Horn (60)
Vice President – Geoscience

James T. Zernell (54)
Vice President – Production

Office Locations

Headquarters

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Fax: 281-210-5101

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Newfield Gulf of Mexico & International
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Houston, Texas 77060
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Fax: 281-405-4242

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Tulsa, Oklahoma 74172
Ph: 918-582-2690
Fax: 918-582-2757

Newfield Rocky Mountains Inc.
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Denver, Colorado 80202
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Fax: 303-893-0103

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Newfield Peninsula Malaysia Inc.
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Chaoyang District, Beijing 100020
P.R. China
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Fax: + 86 (10) 6530 9009

NEWFIELD

Profile

Newfield Exploration Company is an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. Newfield's principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and onshore Texas. Internationally, Newfield focuses on offshore oil developments in Malaysia and China.

Our Business Strategy

- maintaining a diversified portfolio of core assets
- maintaining a strong capital structure
- growing through a combination of development drilling and select acquisitions
- operating our assets and improving operational efficiencies
- attracting and retaining quality employees and ensuring their interests are aligned with our stockholders' interests

Annual Meeting

Our Annual Meeting will be held at 8 a.m., May 4, 2012, in the Williams Resource Center Theatre of our Mid-Continent office located at: One Williams Center, Tulsa, Oklahoma 74172

Stock Information

Our common stock is traded on the NYSE under the symbol "NFX."

Transfer Agent

For information regarding change of address or other matters concerning your shares, please contact our transfer agent directly at:
American Stock Transfer & Trust Company
59 Maiden Lane
New York, NY 10038
877-777-0800 ext. 6820
www.amstock.com

Information

For more information, please visit our website at www.newfield.com. Through our website, you may elect to receive news, S.E.C. filings and other information, including our @NFX publication, by e-mail distribution.

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