NEWFIELD EXPLORATION CO /DE/
Form 10-K
February 26, 2013

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2012

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

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 þ 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 þ 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 þ	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 þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $3.9 billion as of June 30, 2012 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 20, 2013, there were 135,437,292 shares of the registrant s common stock, par value $0.01 per share, outstanding.

Documents incorporated by reference: Portions of the Proxy Statement of Newfield Exploration Company for the Annual Meeting of Stockholders to be held May 2, 2013, which is incorporated by reference to the extent specified in Part III of this Form 10-K.

TABLE OF CONTENTS

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, our or the Company are to Newfield Exploration Company and its subsidiaries. Unless otherwise noted, all information 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 forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). All statements, other than statements of historical facts included in this report, are forward-looking, including information relating 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 statements are typically identified by use of terms such as may, believe, expect, anticipate, intend, estimate, project, target, goal, 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, liquids and natural gas prices and demand;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- general economic, financial, industry or business trends or conditions;
- the impact of, and changes in, legislation, law and governmental regulations, including those related to hydraulic fracturing and climate change;
- land, legal and ownership complexities inherent in the U.S. oil and gas industry;
- the impact of regulatory approvals;
- the availability and volatility 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;
- our commodity hedging arrangements as compared to actual commodity prices;
- the volatility in the commodity futures market;
- the availability of storage, 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;
- terrorism or 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;
- inflation 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;
- the availability (or lack thereof) of acquisition, disposition or combination opportunities; 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 Gulf Coast. Internationally, we have offshore oil developments in Malaysia and China. In February 2013, we initiated a process to evaluate strategic alternatives with respect to our international businesses.

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 Vision, Mission and Core Values

Our vision is to be recognized as a premier independent E&P company, delivering operational excellence, top-tier business results and value to our stockholders, employees and the communities in which we live and work. At Newfield, people, passion and pride combine to power our future. We are dedicated to finding and producing oil, natural gas and related products safely, responsibly and profitably for the benefit of all of our stakeholders. Our founding business principles and core values are the foundation for our success and are practiced every day in managing our current business and guiding our future strategies. These principles and core values follow:

Founding Business Principles:

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

Core Values:

Excellence: We pursue excellence in everything that we do. We are passionate about delivering industry-leading performance throughout our Company.

Integrity: We uphold high ethical standards and treat our stockholders, business partners and neighboring communities with integrity and respect. We play by the rules, do the right thing and allow the character of our employees to define us.

Safety and Environment: We are committed to a culture of safety and responsible environmental stewardship, and to the health and safety of everyone working with us.

Accountability: We are owners and treat every asset, project and investment as our own. We are committed to profitably growing our business and creating long-term stockholder value.

Innovation and Collaboration: We work to leverage the best technologies, develop superior processes and deliver optimum performance. Success is defined as getting the right things done right.

Adaptability: We believe that adaptability is a competitive advantage. We embrace change and constantly evolve our strategies to remain competitive, profitable and relevant.

Our Business Strategy

Our overarching business strategy is to deliver long-term stockholder value through safely, ethically and profitably exploring for, acquiring and developing North American oil and gas resource plays. Over the last five years, we have refined our asset base and focused on creating value through liquids investments. 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 North American assets, with a near-term investment focus on oil and liquids growth;
- 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 North American Assets. Over the last several years, we have transitioned from a conventional, natural gas company to an unconventional company focusing on North American liquids resource plays. By maintaining a diverse asset portfolio we increase our flexibility to respond, and limit our exposure to, the volatility and unique risks our industry faces, such as geologic risks, geographic risks and commodity price risks. In line with this element of our strategy and the continued weakness in natural gas prices, our 2013 plans include:

- allocating substantially all of our planned $1.7 $1.9 billion capital investments to our liquids-rich assets, with approximately 80% of our 2013 capital allocated to domestic operations; and
- limiting investments in natural gas, accepting natural field declines in our natural 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 2013 plans include:

- exploring strategic alternatives to maximize the value of our international businesses; and

- using derivative markets 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 domestic wells we drilled in 2012 had low geologic risk. Since 2000, we have completed several acquisitions that led to the expansion of our operating areas or the establishment of 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. In addition, we are active on a net 125,000-acre position in the Anadarko Basin s prolific Cana Woodford play in Oklahoma, which we acquired during 2011 and 2012. The acquired properties fit well with our existing properties and are in areas where we can leverage our core competencies. In line with this element of our strategy, our 2013 plans include:

- focusing on developing domestic, unconventional resource plays;
- delivering more than 20% year-over-year domestic oil and liquids growth by focusing on developing our fields in the Uinta, Anadarko, Maverick and Williston basins; 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 investments, 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 allows for the more efficient use of both our capital and human resources. In line with this element of our strategy, our 2013 plans include:

- narrowing our focus to North American resource plays;
- improving operational efficiencies by focusing on our unconventional resource plays that have large 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 encouraging all of our people to maintain safe operations, minimize environmental impact and conduct their daily business with the highest of ethical standards;
- focusing on excellent 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.

2013 Outlook and Planned Capital Investments

Our strategy is to focus on North American resource plays, and approximately 80% of our near term investments are being directed to our domestic oil and natural gas liquids drilling programs. For 2013, our capital budget is $1.7 $1.9 billion, excluding capitalized internal costs. We expect to invest $300 $400 million in our international businesses. Our investments will be financed through our cash flows from operations and the use of

our credit facility. In early February 2013, we initiated a process to explore strategic alternatives to maximize the value of our international businesses.

Our domestic liquids production is expected to grow approximately 25% in 2013. As a result of reduced investments over the last several years, our natural gas assets are on natural decline. In 2013, we expect our gas volumes to decline about 14%. Combined, we expect our 2013 production to range from 44 47 MMBOE, or about 4% lower than 2012 volumes before adjusting for any asset sales. In 2012, we sold approximately $630 million in non-strategic assets. Asset sales, natural declines in natural gas assets and a decline in international production are primarily attributable to the decline in production year-over-year.

Our estimated 2013 capital investments by area are shown in the chart below:

Approximately 84% of our expected 2013 domestic oil and gas production is hedged against future changes in commodity prices. For a complete discussion of our hedging activities, a list of open contracts as of December 31, 2012 and the estimated fair value of those contracts as of that date, see Note 4, Derivative Financial Instruments, to our consolidated financial statements.

Our Properties and Plans for 2013

Resource Plays

As discussed above, our strategic focus is on North American resource plays. These plays represent approximately 90% of our proved reserves and 89% of our probable reserves at year-end 2012. In 2013, approximately 75% of our budget will be directed toward our domestic resource plays the Uinta Basin, the Anadarko Basin, the Williston Basin and the Maverick Basin.

Rocky Mountains. As of December 31, 2012, we owned an interest in approximately 780,000 net acres. 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. About one-third of our total proved reserves are located in the Uinta Basin. We are the largest oil producer in the state of Utah, representing about 30% of the state s total oil production. We have approximately 225,000 net acres in the Uinta Basin, and our operations can be divided into two areas: the Greater Monument Butte Unit (GMBU) waterflood and an area to the north and adjacent to the GMBU that we refer to as the Central Basin.

We have been active in the Uinta Basin since our 2004 acquisition of the GMBU. Since that time, we have drilled approximately 1,500 wells in the unit and today have approximately 1,800 productive oil wells. GMBU is the largest federal unit in the lower 48 states. The primary producing horizon in the unit is the shallow Green River. In 2011, we expanded our footprint in the area and today have about 140,000 prospective net acres in the Central Basin. Since that time, we have been exploring deeper vertical and horizontal plays on this acreage, including the Uteland Butte and Wasatch formations.

We have approximately $380 million allocated to our Uinta Basin programs in 2013. We expect approximately half of the budget will be allocated to the Central Basin. Our net production from the Uinta Basin at year-end 2012 was approximately 20,000 BOEPD, comprised of 14,000 BOPD, 700 BOEPD of NGLs and 31 MMcf/d. We are planning to drill about 30 wells to test the pressured section of the Uteland Butte and Wasatch formations. This program follows the success of our 2012 program and the drilling of approximately 50 wells in these plays to date. As of early February 2013, our estimate of potential remaining locations in the Uinta Basin totaled approximately 6,800 and could materially increase with continued drilling success.

Williston Basin. We have approximately 100,000 net acres in the Williston Basin, of which 41,000 is being actively developed in the Bakken and Three Forks plays of North Dakota. Our activities today are largely development focused and we are drilling multi-well pads with lateral lengths as long as 10,000 feet. Our net production at year-end 2012 was approximately 10,500 BOEPD, comprised of 7,800 BOPD, 1,000 BOEPD of NGLs and 10 MMcf/d. We are increasing our activities in the area in 2013 and currently have allocated approximately $230 million to the Williston Basin. Plans include the operation of four rigs in the basin throughout the year. We expect our production from the Williston Basin to increase about 15% over 2012 levels.

Mid-Continent. More than one-third of our total proved reserves are located in our Mid-Continent region. We have more than 10 years of experience developing the Woodford Shale. Our acreage includes more than 300,000 net acres in the Woodford, which includes positions in the dry gas Arkoma Basin Woodford and the liquids-rich Cana Woodford in the Anadarko Basin. Our position in the Anadarko Basin was assembled within the last three years.

Cana Woodford. We have about 125,000 net acres that are prospective for development in the Cana Woodford. As of February 2013, we had drilled approximately 30 wells in the Cana Woodford, with wells yielding high volumes of oil and natural gas liquids. For 2013, we have allocated approximately $360 million to concentrated development drilling in the Cana Woodford play. We are planning to operate up to six rigs throughout the year. At year-end 2012, our production was more than 10,000 BOEPD, consisting of 2,300 BOPD, 3,200 BOEPD of NGLs and 28 MMcf/d, and is expected to more than double by year-end 2013.

Arkoma Woodford. We have significant dry gas production from the Arkoma Woodford. The area represents about one third of our total consolidated proved reserves. Our investment levels in this area have been significantly curtailed over the last three years due to low natural gas prices, as our investments have been shifted to liquids-rich plays. As of December 31, 2012, we had approximately 160,000 net acres in the Arkoma Basin and our net production was approximately 26,500 BOEPD, consisting of 300 BOPD, 200 BOEPD of NGLs and 156 MMcf/d. Our production in this area is on natural decline. Substantially all of our acreage in this region is held-by-production.

Granite Wash. We have approximately 50,000 net acres prospective for development in the Granite Wash, located in the Anadarko Basin of northern Texas and western Oklahoma. Our largest producing field in the Granite Wash is Stiles/Britt Ranch. Our recent drilling activity in the region has focused on the oil-rich Hogshooter formation where we expect to drill four to six wells in 2013. At year-end 2012, our net production from the area was approximately 17,000 BOEPD, consisting of 3,000 BOPD, 1,700 BOEPD of NGLs and 73 MMcf/d.

Onshore Gulf Coast. We have approximately 185,000 net acres in the Eagle Ford, located in the Maverick Basin of Maverick, Dimmit and Zavala counties, Texas. To date, we have completed more than 60 wells in the basin and believe that approximately 25,000 of the acres in the southeast portion are developable under current commodity prices and drilling costs. We expect to run a one to two operated rig program in the area in 2013 and plan to drill about 35 wells. Our development is focused on pad drilling with planned lateral lengths of up to 10,000 feet. Our planned capital investments for 2013 are about $275 million. At year-end 2012, our net daily production in the Maverick Basin was approximately 5,100 BOEPD, consisting of 2,900 BOPD, 950 BOEPD of NGLS and 8 MMcf/d, and production is expected to grow 75% over 2012 levels.

Conventional Plays

We have operations in conventional plays onshore Gulf Coast and offshore Malaysia and China.

Onshore Gulf Coast. Over the last two years, we have slowed our activities in many of our conventional natural gas plays and monetized non-strategic assets. The proceeds from these asset sales have been invested in our unconventional resource plays. As of December 31, 2012, we owned an interest in approximately 139,000 net acres in conventional onshore plays. At year-end 2012, our net production was approximately 8,500 BOEPD, consisting of 500 BOPD, 500 BOEPD of NGLs and 45 MMcf/d, from our conventional onshore Texas assets. We expect our production in conventional plays to continue to decline in 2013 due to a lack of investment.

International. In early 2013, we initiated a process to explore strategic alternatives to maximize the value of our international businesses in southeast Asia. With ongoing oil developments in the region, we expect that our capital investments in the area will range from $300 $400 million in 2013. Our international net production at year-end 2012 was approximately 31,000 BOEPD, consisting of 30,000 BOPD and 5 MMcf/d. As of February 20, 2013, we have an interest in approximately 3.3 million net acres offshore Malaysia and approximately 290,000 net acres offshore China. In 2013, approximately $150 million is allocated to the continued development of our Pearl field, located in the Pearl River Mouth Basin offshore China. The Pearl field is expected to commence production in early 2014 at a net rate of approximately 15,000 BOPD. We expect our international production to decline 25 30% in 2013 as a result of natural declines in Malaysia and changes in the economic sharing of production under the terms of our production sharing agreements.

Reserves

At year-end 2012, we had proved reserves of 3.4 Tcfe (566 MMBOE), 13% less than year-end 2011. At the end of 2012, our proved reserves were 48% oil and NGLs and 53% are proved developed. Our probable reserves were 51% oil and 15% NGLs. Our year-end 2012 proved reserve life index was approximately 11 years. Our 2012 production was approximately 50 MMBOE.

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 by volume, the Arkoma Woodford Shale and the Greater Monument Butte Unit, accounted for about 41% of the total net present value of our proved reserves at December 31, 2012.

	Percentage of Proved Reserves	**Percentage of Probable Reserves**
Located domestically	94%	91%
Located onshore	94	91
10 largest fields	88	92
2 largest fields	55	41

Largest Fields. The table below sets forth for our largest fields (those whose reserves are greater than 10% of our total proved reserves), which are the Greater Monument Butte Unit and the Arkoma 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 cost structure, see Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations* Results of Operations.

	Year Ended December 31,		
	2012	**2011**	**2010**
Production:			
Crude oil and condensate (MBbls)			
Greater Monument Butte Unit	3,720	3,297	3,554
Arkoma Woodford Shale	130	107	71
Natural gas (Bcf)			
Greater Monument Butte Unit	1.9	1.9	2.6
Arkoma Woodford Shale	63.2	69.4	76.2
NGLs (MBbls)			
Greater Monument Butte Unit	133	118	111
Arkoma Woodford Shale	86	110	97
Average Realized Prices:			
Crude oil and condensate (per Bbl)			
Greater Monument Butte Unit	$ 77.58	$ 78.19	$ 65.50
Arkoma Woodford Shale	$ 90.54	$ 88.80	$ 74.23
Natural gas (per Mcf)			
Greater Monument Butte Unit	$ 1.71	$ 3.15	$ 3.23
Arkoma Woodford Shale	$ 2.35	$ 3.57	$ 3.86
NGLs (per Bbl)			
Greater Monument Butte Unit	$ 63.92	$ 73.90	$ 56.39
Arkoma Woodford Shale	$ 27.64	$ 33.81	$ 28.48
Average Production Cost:			
Greater Monument Butte Unit (per BOE)	$ 16.48	$ 14.45	$ 9.48
Arkoma Woodford Shale (per Mcfe)	$ 1.80	$ 1.58	$ 1.16

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 our 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, gas and NGL reserves and future cash flows from those reserves will most likely vary from our estimates* under Item 1A, Risk Factors, 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, 2012, 2011 and 2010 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, 2012.

	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs[2] (MMBbls)	Total (Bcfe)[1]
Proved Developed Reserves:				
Domestic	92	1,042	15	1,680
International:				
Malaysia	14			86
China	4			25
Total International	18			111
Total Proved Developed	110	1,042	15	1,791
Proved Undeveloped Reserves:				
Domestic	111	713	22	1,511
International:				
Malaysia	1			5
China	15			91
Total International	16			96
Total Proved Undeveloped	127	713	22	1,607
Total Proved Reserves	237	1,755	37	3,398
Probable Developed Reserves:				
Domestic	1	15	2	33
International:				
Malaysia	6			34
China	1			6
Total International	7			40
Total Probable Developed	8	15	2	73
Probable Undeveloped Reserves:				
Domestic	131	488	42	1,524
International:				
Malaysia	3	73		94
China	2			12
Total International	5	73		106
Total Probable Undeveloped	136	561	42	1,630
Total Probable Reserves	144	576	44	1,703

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

(2) Historically, we reported natural gas liquid (NGL) volumes combined with oil and condensate production. Effective in our Form 10-K for the period ended December 31, 2012, we began reporting our NGL production separately from our crude oil and condensate production. As such, all production volumes and average realized prices for periods prior to 2012 have been reclassified for comparability between periods.

Proved Reserves. Our year-end 2012 proved reserves of 3,398 Bcfe decreased 13% compared to our proved reserves at year-end 2011. Our reserves consisted of 1,512 Bcfe proved developed producing, 279 Bcfe proved developed non-producing and 1,607 Bcfe proved undeveloped reserves. Our proved crude oil, condensate and NGL reserves at year-end 2012 were 274 million barrels, compared to 263 million barrels at year-end 2011, an increase of 4%. The increase is primarily attributable to an increase of 21 million barrels of NGLs, partially offset by a decrease of 10 million barrels of oil and condensate. At December 31, 2012, our proved natural gas reserves were 1,755 Bcf which represented a decrease of 25% compared to 2011. At year-end 2012, 87% of our proved liquid reserves were crude oil or condensate.

At December 31, 2012, the SEC pricing for natural gas was $2.76 per MMBtu, a 33% decline compared to the prior year end. As a result, we revised our total proved reserves downward by 616 Bcfe. The majority of the price revision was attributable to the Arkoma Woodford Shale. Excluding price, the net impact of all other revisions was a positive 70 Bcfe. Additionally, during 2012, our drilling activities resulted in additions to our proved reserves of 512 Bcfe which offset the majority of the effect of the aforementioned price revisions. Consistent with our continued focus on domestic liquids, our additions reflected a 64% total liquids component, which was 38 million barrels of oil and 17 million BOE of NGLs.

Proved Undeveloped Reserves. Our proved undeveloped reserves at December 31, 2012 were 1,607 Bcfe compared to 1,782 Bcfe at December 31, 2011. Liquids comprised 56% of our total proved undeveloped reserves as of December 31, 2012. During 2012, we invested approximately $0.7 billion of drilling, completion and facilities-related capital to convert 161 Bcfe of our December 31, 2011 proved undeveloped reserves into proved developed reserves. Additionally, we invested approximately $0.1 billion of facilities-related capital in the continued development of our proved undeveloped reserves that were not fully converted to proved developed status as of December 31, 2012. During 2012, we added 362 Bcfe of new proved undeveloped reserves through drilling activities, a 33 Bcfe net reduction due to sales and acquisitions, and negative revisions of 342 Bcfe primarily as a result of the decrease in SEC pricing for natural gas mentioned above.

Proved undeveloped reserve quantities are limited by the activity level of development drilling we expect to undertake during the 2013-2017 five-year period. Of the 1,607 Bcfe of proved undeveloped reserves at December 31, 2012, a limited amount is associated with the Greater Monument Butte Unit waterflood that will be developed more than five years from the date of first booking. The waterflood requires the timely and orderly drilling of production and injection wells, conversion of producing wells to injection wells and the injection of certain amounts of water before all producing wells are drilled to optimize oil recovery and project economics. Similarly, and for comparison, at year end 2011, a limited amount of our proved undeveloped reserves were associated not only with the Greater Monument Butte Unit waterflood, but also other development projects, such as the Arkoma Woodford Shale, the scope and scale of which is such that if the projects were terminated, for whatever reason, a significant portion of previously invested capital would be lost. 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 2010 through 2012, we developed 13%, 19% and 9%, 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 probable reserves of 1,703 Bcfe at December 31, 2012, consisted of 73 Bcfe of developed and 1,630 Bcfe of undeveloped reserves, as compared to probable developed and undeveloped reserves at year-end 2011 of 22 Bcfe and 2,539 Bcfe, respectively. Our probable crude oil, condensate and NGL reserves at year-end 2012 were 188 million barrels, compared to 151 million barrels at year-end 2011, an increase of 24%.

At December 31, 2011, our probable reserves were 2,561 Bcfe. During 2012, 204 Bcfe of our probable reserves were converted to proved reserves. During 2012, we added probable reserves of 676 Bcfe through our exploration and development activities, of which 41% were crude oil and 23% were NGLs. Additional changes to probable reserves included negative price related revisions of 1,222 Bcfe as a result of lower natural gas prices compared to 2011, property sales of 249 Bcfe, acquisitions of 4 Bcfe and positive performance-related revisions of 137 Bcfe. As a result, our probable reserves at December 31, 2012 were 1,703 Bcfe.

Reserves Sensitivities

To determine our year-end 2012 reserves estimates, we utilized SEC pricing for natural gas and crude oil, which was $2.76 per MMBtu and $94.84 per barrel, respectively.

Using crude oil prices of $85 and $70 per barrel, the quantity of our domestic proved developed reserves decreases by 1% and 2% respectively, due to shortening of the economic life. Our proved undeveloped oil reserves are primarily in the Uinta Basin of Utah and the Williston Basin of North Dakota. At crude oil prices of $70 per barrel, and without a commensurate change in cost, our domestic proved undeveloped reserves would decrease by approximately 17 MMBOE, and we would reduce our future capital investment over the next five years by approximately $350 million. As a result of the foregoing, at $85 and $70 per barrel our domestic proved reserves would decrease by 1% and 5% respectively.

Our planned capital activity focuses on liquids versus natural gas and is limited by the level of development drilling we expect to undertake in the future. At natural gas prices below $2.50 per MMBtu, our domestic proved developed reserves would decrease by 2% due to shortening the economic life. Additionally, at this lower gas price, and without a commensurate change in cost, our domestic proved undeveloped reserves would decrease by approximately 235 Bcfe, and we would reduce our future capital investment over the next five years by approximately $300 million. At higher natural gas prices of $3.00, $3.50 and $4.00 per MMBtu, and without reconfiguring to optimize our development plan, the pre-tax present value of our proved reserves would increase by $175, $542 and $910 million, respectively.

Under the terms of our production sharing contracts (PSC) 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.

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Domestic:						
Productive[1]	190	90.5	263	159.2	360	215.6
Nonproductive[2]	2	2.0	2	1.0	6	3.0
International:						
China:						
Nonproductive[3]			1	1.0	2	2.0
Malaysia:						
Productive[4]			1	0.7	1	0.4
Nonproductive[5]	2	0.9			3	2.6
International Total:						
Productive			1	0.7	1	0.4
Nonproductive	2	0.9	1	1.0	5	4.6
Exploratory well total	194	93.4	267	161.9	372	223.6
Development wells:						
Domestic:						
Productive	214	170.9	253	199.6	243	189.8
International:						
China:						
Productive					5	0.6
Malaysia:						
Productive	12	7.7	17	5.8	7	4.3
Nonproductive					1	0.6
International Total:						
Productive	12	7.7	17	5.8	12	4.9
Nonproductive					1	0.6
Development well total	226	178.6	270	205.4	256	195.3

(1) Includes 29 gross (26.3 net), 61 gross (37.6 net) and 126 gross (91.1 net) wells in 2012, 2011 and 2010, respectively, that are not exploitation wells.

(2) Includes 2 gross (2.0 net) and 6 gross (3.0 net) wells in 2012 and 2010, respectively, that are not exploitation wells.

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

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

(5) Includes 2 gross (0.9 net) and 2 gross (2.0 net) wells in 2012 and 2010, respectively, that are not exploitation wells.

We were in the process of drilling 1 gross (0.9 net) exploratory well, 3 gross (2.2 net) exploitation wells and 27 gross (18.9 net) development wells domestically at December 31, 2012. Internationally, we were drilling 1 gross (0.4 net) exploratory well in Malaysia at December 31, 2012.

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, 2012 and the location of, and other information with respect to, those wells. As of December 31, 2012, we had 10 gross (3.1 net) oil wells with multiple completions.

	Company Operated Wells		Outside Operated Wells		Total Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
Domestic:						
Oil	2,398	1,942.1	846	73.7	3,244	2,015.8
Natural gas	1,452	1,158.7	1,135	211.6	2,587	1,370.3
International:						
Offshore China:						
Oil			39	4.7	39	4.7
Offshore Malaysia:						
Oil	36	22.4	22	11.0	58	33.4
Natural gas			1	0.5	1	0.5
Total International:						
Oil	36	22.4	61	15.7	97	38.1
Natural gas			1	0.5	1	0.5
Total:						
Oil	2,434	1,964.5	907	89.4	3,341	2,053.9
Natural gas	1,452	1,158.7	1,136	212.1	2,588	1,370.8
Total	3,886	3,123.2	2,043	301.5	5,929	3,424.7

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 established by the various operating agreements or contracts. The charges customarily vary with the depth and location of the well being operated.

Acreage Data

As of December 31, 2012, we owned interests in developed and undeveloped oil and gas acreage set forth in the table below. Domestic ownership interests are onshore and generally take the form of working interests in oil and gas leases that have varying terms. International ownership interests are offshore and generally arise from participation in PSCs.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
	(In thousands)			
Domestic:				
Mid-Continent	537	328	261	153
Rocky Mountains	307	200	782	586
Onshore Gulf Coast	537	483	60	37
Appalachia			69	34
Total Domestic	1,381	1,011	1,172	810
International:				
China	22	3	287	287
Malaysia	201	104	4,069	1,460
Total International	223	107	4,356	1,747
Total	1,604	1,118	5,528	2,557

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 438,654 gross (107,433 net) acres. These interests do not expire.

	Undeveloped Acres Expiring									
	2013		2014		2015		2016		2017	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(In thousands)									
Domestic:										
Mid-Continent	63	28	109	67	54	35	20	11	3	2
Rocky Mountains	51	17	42	25	316	273	73	35	68	67
Onshore Gulf Coast	23	18	16	13	3	1				
Total Domestic	137	63	167	105	373	309	93	46	71	69
International:										
Offshore China	287	287								
Offshore Malaysia	1,177	388	1,079	431	1,813	641				
Total International	1,464	675	1,079	431	1,813	641				
Total	1,601	738	1,246	536	2,186	950	93	46	71	69

Title to Properties

We believe that we have satisfactory title to 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 PSCs or exploration licenses. As is customary in the industry in the case of undeveloped properties, often limited 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, gas and NGLs are 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 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 at this time. In late 2011 and early 2012, we signed two separate long-term agreements (7 and 10 years, respectively) for a combined 38,000 BOPD of refining capacity in the Salt Lake City, Utah area. These agreements are expected to add approximately 20,000 BOPD of new refinery capacity in the region. Specifically, in December 2011, we executed a crude oil supply agreement with Tesoro Corporation to provide 18,000 BOPD of supply capacity at Tesoro s refinery in Salt Lake City, Utah. This agreement spans a seven-year period with limited commitments expected to commence in mid-2013 and increase to 18,000 BOPD over the next few years. In addition, in January 2012, we executed a crude oil supply agreement with HollyFrontier Corporation to provide approximately 20,000 BOPD of supply capacity at HollyFrontier s Woods Cross, Utah refinery. This agreement spans a 10-year period, with limited commitments expected to commence upon the refiner completing the expansion of their facility, which is expected in late 2014 or early 2015, and increases to 20,000 BOPD over the next few years. We continue to seek additional capacity to accommodate our growth plans for the Uinta Basin, including the use of rail and pipelines to access new markets outside of the Salt Lake City area. 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. 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.

Segment Information

For additional information on operations by segment, see Note 13, Segment Information, to our consolidated financial statements in Item 8 of this report.

Employees

As of February 20, 2013, we had 1,760 employees. All but 234 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;
- protection of private and public surface and ground water supplies;
- 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;

transportation of production; and

export of natural gas.

Federal Regulation of Drilling and Production. Many of our domestic oil and gas leases are granted by the federal government and administered by the BSEE, ONRR or the BLM, all federal agencies. BLM leases contain relatively standardized terms and require compliance with detailed BLM, BSEE and ONRR regulations. 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. Under certain circumstances, the BLM or the BSEE, 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.

State and Local Regulation of Drilling and Production. We own interests in properties located onshore in a number of states. 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;
- the development of emergency response and spill contingency plans; and
- protection of private and public surface and ground water supplies.

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.

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 CWA also requires 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, that became effective in 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 the BLM may need to prepare 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 on operations 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.

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 affect 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 a variety of tax, energy-related or environmental market-based mechanisms to promote or induce the reduction of emissions of greenhouse gases by several commercial or industrial sectors. 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 greenhouse gases. Further, on April 2, 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an air pollutant under the federal Clean Air Act. On April 24, 2009, EPA responded to the Massachusetts, et al. v. EPA decision with a proposed endangerment finding that the current and projected concentrations of greenhouse gases (GHG) in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change. That endangerment finding has led to several EPA rules and proposed rulemakings to regulate GHGs. However, several other federal agencies are considering or implementing rules to reduce GHG emissions. Although it is not possible at this time to predict whether future GHG mitigation legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted to address greenhouse gas 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 greenhouse gas 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, some of which have passed, regulations 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 or own interests, such as Colorado, 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.

Pursuant to authority delegated to it by the Energy Policy Act of 2005, or EPAct 2005, FERC promulgated anti-manipulation regulations establishing violation enforcement mechanisms 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 these requirements, similar to violations of other NGA and FERC enforcement authorities, may be subject to investigation and penalties of up to $1 million per day per violation. FERC may also order disgorgement of profit and corrective action. We believe, however, that neither the EPAct 2005 nor the regulations promulgated by FERC as a result of the EPAct 2005 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 market manipulation and anti-disruptive requirements under the Commodity Exchange Act, or CEA, as amended by the Dodd-Frank Financial Reform Act, and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. CFTC 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, EPA, 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. These regulations are 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 Supplementary Data*.

Commonly Used Oil and Gas Terms

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

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

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.

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.

BOEPD. Barrels of oil equivalent per day.

BOPD. Barrels of oil per day.

BSEE. Bureau of Safety and Environmental Enforcement.

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 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.

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.

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

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.

Liquids-rich. Formations that contain crude oil or natural gas liquids (NGLs) instead of, or as well as, natural gas.

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

Mcf. One thousand cubic feet of natural gas.

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

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

MMBOE. One million barrels of oil equivalent.

MMBtu. One million Btus.

Mcf/d. One thousand cubic feet of natural gas produced per day.

MMMBtu. One billion Btus.

Net acres or net wells. The sum of the fractional working interests we own in gross acres or gross wells.

NGL. Natural gas liquid. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane and natural gasolines.

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.

ONRR. Office of Natural Resources Revenue.

Probable developed reserves. In general, probable 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.

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.

Probable undeveloped reserves. In general, probable 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.

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 natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government 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.

SEC pricing. The unweighted average first-day-of-the-month commodity price for crude oil or natural gas for the prior twelve months, adjusted for market differentials. The SEC provides a complete definition of prices in *Modernization of Oil and Gas Reporting* (Final Rule).

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, gas and NGL 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, gas and NGLs. Lower prices may reduce the amount of oil, gas and NGLs that we can economically produce. Oil, gas and NGL prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital.

The market prices for crude oil, natural gas and NGLs depend on factors beyond our control. Among the factors that can cause fluctuations are:

- the domestic and foreign supply of oil, natural gas and NGLs;
- 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 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;
- the actions taken by foreign oil and gas producing nations; and
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental regulation.

Significant declines in crude oil, natural gas and NGL prices for an extended period may have the following effects on our business:

- limiting our access to sources of capital, such as equity and long-term debt;
- causing us to delay or postpone capital projects;

reducing reserves and the amount of products we can economically produce;

reducing revenues, income and cash flows; or

reducing the carrying value of our assets.

We have substantial capital requirements to fund our business plans that we expect to be greater than cash flows from operations. Limited liquidity would likely negatively impact our ability to execute our business plan. We anticipate that our 2013 capital investment levels will exceed our estimate of cash flows from operations. We expect to sell non-strategic assets and use available capacity under our credit arrangements to fund the shortfall. Actual levels of capital expenditures may vary significantly due to many factors including drilling results, commodity 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:

we are unable to access the capital markets at a time when we would like, or need, to raise capital;

- 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.

Actual quantities of oil, gas and NGL reserves and future cash flows from those reserves will most likely vary from our estimates. Estimating accumulations of oil, gas and NGLs 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, gas and NGL 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 our prepared estimates. Estimates prepared by others might differ materially from our estimates.

Actual quantities of oil, gas and NGL reserves, future production, oil, gas and NGL 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 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, gas and NGL 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 reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on SEC pricing, 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.

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 flows. 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.

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 $1.5 billion ($948 million after-tax) at December 31, 2012. 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.

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 are often uncertain of 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.

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 typhoon or other adverse weather conditions. These conditions could cause substantial damage to facilities and interrupt production. Our 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.

Failure or loss of equipment, as the result of equipment malfunctions, cyber-attacks or natural disasters, could result in property damages, personal injury, environmental pollution and other damages for which we could be liable. Catastrophic occurrences giving rise to litigation, such as a well blowout, explosion or fire at a location where our equipment and services are used, may result in substantial claims for damages. Ineffective containment of a drilling well blowout or pipeline rupture could result in extensive environmental pollution and substantial remediation expenses. If our production is interrupted significantly, our efforts at containment are ineffective or litigation arises as the result of a catastrophic occurrence, our cash flows, and, in turn, our results of operations could be materially and adversely affected.

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 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, gas and NGLs 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 into 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. In addition, 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.

Further, changes to existing environmental 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 regulating greenhouse gas (GHG) emissions in some manner. In the absence of dedicated federal legislation to address climate change mitigation, the U.S. EPA has taken several actions and rulemakings to regulate, measure or monitor GHG emissions under the existing provisions of the Clean Air Act, or CAA. The EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, as well as from certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities on an annual basis. The new regulations could impact certain facilities in which we have interests (legal, equitable, operated or non-operated) by increasing regulatory risks and reporting requirements.

In December 2009, the U.S. EPA also issued an endangerment finding under the CAA concluding that the current and projected concentrations of GHGs in the atmosphere from motor vehicles threaten the public health and welfare of current and future generations. The finding, once made, required the EPA to begin regulating GHG emissions from new cars and light trucks under the CAA. Indirectly, it also triggered the EPA s obligation to regulate GHG emissions under existing relevant air permitting programs for large stationary sources. On January 2, 2011, the EPA initiated Prevention of Significant Deterioration (PSD) permitting requirements for carbon dioxide and other GHGs from large and modified stationary sources. Permits limiting GHGs have been issued for a variety of new or modified facilities under the Clean Air Act PSD program. GHG emissions also trigger Title V operating permit requirements for new and existing sources that exceed certain established emission thresholds. The PSD permitting requirement is triggered when a new or modified facility emits specified levels of GHGs (e.g., 75,000-100,000 tons per year). Emission levels in excess of these thresholds can then trigger preconstruction permit requirements and application of best available control technology (BACT) as determined on a source-by-source basis. In most cases, based on cost, the BACT compliance option selected for GHGs is increased energy efficiency.

In addition, the U.S. Congress continues to consider adopting tax, energy or environmental market-based mechanisms to promote or require the reduction of GHG emissions from certain industrial sectors. Any such legislation or regulatory programs, depending on design and scope, could increase the cost of oil and gas production. Some states like California have implemented state-wide GHG mitigation programs to reduce GHG emissions through a mixture of regulatory programs, including a low carbon fuel standard and cap-and-trade market applicable to, among others, electric utilities and transportation fuels.

Further, the U.S. Congress has previously proposed legislation that would directly impact our industry. 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 64% of our proved reserves and approximately 67% of our probable reserves at year-end 2012. 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, the Bureau of Land Management (BLM) and other federal regulatory agencies have taken steps to review or impose federal regulatory requirements. Certain states in which we operate, 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. On September 11, 2012, the RCT approved new regulations relating to the commercial recycling of produced water and/or hydraulic-fracturing flowback fluid, and on December 17, 2012, proposed revised amendments to rules of casing, cementing, well control and completion of oil and gas wells.

In the past three years, news reports indicate that at least 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 operations, 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 drilling 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. The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and recently released draft permitting guidance for hydraulic fracturing activities using diesel. Further, on November 23, 2011, the EPA announced that it was granting in part a petition to initiate rulemaking under the Toxic Substances Control Act, relating to chemical substances and mixtures used in oil and gas exploration and production. In addition, on May 11, 2012, the BLM issued a proposed rule that would require the public disclosure of chemicals used in hydraulic fracturing operations, set requirements for well-bore integrity and establish flowback water standards for all hydraulic fracturing operations on federal public lands and American Indian Tribal lands. The proposed rule also required that an operator certify, in writing, that (a) the stimulation design complies with all federal, state, tribal and local regulations; (b) the stimulation was completed in accordance with the design approved by BLM and all applicable regulations; and (c) the well-bore integrity was maintained during the fracturing process and flowback water was properly stored, treated and disposed. On January 22, 2013, however, BLM withdrew the proposed disclosure rule and intends to release a revised proposal in 2013. 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 in 2013 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.

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 RTC 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 (a) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, (b) 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 (c) 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 Safe Drinking Water Act or other regulatory mechanisms.

Further, on August 16, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA finalized rules under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA regulations include NSPS standards for completions of hydraulically-fractured gas wells. Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the gas using green completions. After January 1, 2015, operators must capture the gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAPS include specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. We are currently evaluating the effect these regulations could have on our business. Compliance with such regulations could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

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.

We could be adversely affected by the credit risk of financial institutions. We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry. In the event of default of a counterparty, we would be exposed to credit risks. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges and insurance companies in the form of claims under our policies. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender s commitment under our credit facility.

Our use of oil and natural 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. 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 24 to 36 months to reduce our exposure to fluctuations in oil and natural gas prices. As of December 31, 2012, we had no outstanding derivative contracts related to our NGL production. 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 relevant underlying commodity reference prices and those of our physical pricing points. While the use of hedging arrangements limits the downside risk of adverse price movements, their use also may limit future benefits from favorable price movements 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.

The use of hedging transactions also involves the risk that counterparties, which generally are financial institutions, will be unable to meet the financial terms of such transactions. 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 swaps could adversely affect the costs of, or our ability to enter into, those transactions. On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Reform Act) was enacted to establish federal oversight and regulation of the over-the-counter derivatives market and over entities, such as Newfield, that participate in that market. The Dodd-Frank Reform Act includes provisions that require certain over-the-counter derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading platform. The Commodity Futures Trading Commission (CFTC) has begun to formally determine the types of swaps that will be subject to the mandatory clearing and exchange trading requirements. Non-financial entities that use swaps to hedge or mitigate commercial risk, often referred to as end-users, can choose to exempt their hedging transactions from these clearing and exchange trading requirements. If our swap activities are not exempt from mandatory clearing or exchange trading, or from margin requirements for uncleared swaps, we could be subject to higher costs, including from higher margin requirements, for those activities.

There are substantial costs associated with the Dodd-Frank Reform Act that create disincentives for end-users like Newfield to hedge their commercial risk associated with anticipated production of oil and gas. The Dodd-Frank Reform Act and related rules and regulations promulgated by CFTC could potentially increase the cost of Newfield s swap contracts (including through requirements to post margin or collateral for cleared and uncleared swaps, which could adversely affect our available liquidity), materially alter the terms of our swap contracts, reduce the availability of swaps to hedge or mitigate risks we encounter, reduce our ability to monetize or restructure existing swap contracts, and increase our regulatory compliance costs related to our swap activities. In addition, if we reduce our use of swaps, our results of operations and cash flows may become more volatile and less predictable, which could adversely affect our results of operations, cash flows, or our ability to plan for and fund capital expenditures. It is also possible that the Dodd-Frank Reform Act and related rules and regulations could affect prices for commodities that we purchase, use or sell, which, in turn, could adversely affect our liquidity or financial condition.

The CFTC also adopted rules under the Dodd-Frank Reform Act to expand aggregate position limits to include certain swaps that are economically equivalent to certain types of commodity futures, including specified energy commodity futures and related transactions, which would apply to swap transactions in which we engage beyond certain thresholds. Certain *bona fide* hedging transactions or positions would have been exempt from those limits, and the rules could require additional oversight monitoring and reporting. In September 2012, a U.S. federal district court vacated the position limits regulations and remanded them to the CFTC for additional action. On November 15, 2012, CFTC filed a notice of appeal of that court decision. If the position limit regulations are ultimately reinstated or readopted substantially in the form originally adopted, they could result in additional compliance costs and alter our ability to effectively manage our commercial risks.

Some of our undeveloped leasehold acreage is subject to leases that will expire unless production is established on units containing the acreage. Unless we establish production in paying quantities on units containing certain of these leases during their terms, the leases will expire and we will lose the right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

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. In recent years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of 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 gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain U.S. production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

These proposals were also included in President Obama s Proposed Fiscal Year 2013 Budget. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of such legislation or any other 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.

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, the oil is heated in the field and transported in insulated trucks during shipping. At this time, our transportation options are limited. Substantially all of our production is transported by truck to refiners in the Salt Lake City area. We are exploring the feasibility of transporting future oil volumes by rail or pipeline. 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 2013. In addition, we have executed long-term supply agreements (7 and 10 years) with Tesoro and HollyFrontier, who are expanding their local refineries. Our commitments begin in 2013 and 2014, respectively. The inability of Tesoro or HollyFrontier to complete their expansions or an extended loss of any of our largest purchasers or inability to secure new markets outside of the Salt Lake City area could have a material adverse effect on us because there are limited purchasers of our black and yellow wax crude oil.

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 available 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.

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;
- cultural differences;
- 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 may also 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.

Exploration in international 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 our international 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.

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 national oil and gas companies, major oil and gas companies, independent oil and gas companies, individual producers, financial buyers as well as participants in other industries supplying energy and fuel to consumers. 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 compete for the personnel and equipment required to explore, develop and operate properties. Competition is also prevalent in the marketing of oil, gas and NGLs. Our competitors also may have established long-term strategic positions and relationships in areas in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for certain drilling rights if our competitors are seeking the same.

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.

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.

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 our 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.

We are exposed to counterparty credit risk as a result of our receivables. We are exposed to risk of financial loss from trade, joint venture, joint interest billing, and other receivables. We sell our crude oil, natural gas and NGLs to a variety of purchasers. Some of our purchasers and non-operating partners may experience liquidity problems and may not be able to meet their financial obligations to us. Nonperformance by a trade creditor or non-operating partner could result in financial losses.

Hurricanes, typhoons, tornadoes and other natural disasters could have a material adverse effect on our business, financial condition and results of operations. Hurricanes, typhoons, tornadoes and other natural disasters can potentially destroy thousands of business structures and homes and, if occurring in the Gulf Coast region of the United States, could disrupt the supply chain for oil and gas products. Disruptions in supply could have a material adverse effect on our business, financial condition, results of operations and cash flow. Damages and higher prices caused by hurricanes, typhoons, tornadoes and other natural disasters could have an adverse effect on our financial condition due to the impact on the financial condition of our customers.

Restrictive covenants in the agreements governing our indebtedness and other financial obligations may reduce our operating flexibility. The indenture governing our outstanding notes and the agreements governing our other indebtedness and financial obligations contain, and any indenture that will govern other debt securities issued by us may contain, various covenants that limit our ability and the ability of specified subsidiaries of ours to, among other things:

- incur additional indebtedness;
- purchase or redeem our outstanding equity interests or subordinated debt;
- make specified investments;
- create liens;
- sell assets;
- engage in specified transactions with affiliates;
- engage in sale-leaseback transactions; and
- effect a merger or consolidation with or into other companies or a sale of all or substantially all of our properties or assets.

These restrictions could limit our ability to:

- obtain future financing;
- make needed capital expenditures;
- withstand a future downturn in our business or the economy in general; or
- conduct operations or otherwise take advantage of business opportunities that may arise.

Some of the agreements governing our indebtedness and other financial obligations also require the maintenance of specified financial ratios and the satisfaction of other financial conditions. Our ability to meet those financial ratios and conditions can be affected by unexpected downturns in business operations beyond our control, such as a volatile energy commodity cost environment or an economic downturn. Accordingly, we may be unable to meet these ratios and conditions. This failure could impair our operating capacity and cash flows and could restrict our ability to incur debt or to make cash distributions, even if sufficient funds were available.

Our breach of any of these covenants could result in a default under the terms of the relevant indebtedness, which could cause such indebtedness or other financial obligations to become immediately due and payable. If the lenders accelerate the repayment of borrowings or other amounts owed, we may not have sufficient assets to repay our indebtedness or other financial obligations, including our outstanding notes and any future debt securities.

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 and our omnibus stock plans 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***

Not applicable.

Item 3. ***Legal Proceedings***

In August 2010, we received a Notice of Violation (NOV) from the Environmental Protection Agency (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 (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 and 2009 filings (for 2009 and 2008) did not meet the financial ratio tests that are acceptable as one form of required financial assurance under SDWA regulations. The NOV was completely administrative in nature and did not contain any allegations of environmental spills, releases or pollution. Upon receipt of the NOV, we promptly complied with the EPA s request to put in place alternate financial assurance for the wells even though we in fact believed we did meet the financial ratio tests. We held preliminary discussions with the EPA regarding potential settlement of this matter; however, the EPA determined that the NOV could not be resolved within the EPA s settlement authority under the SDWA and required a referral to the Department of Justice (DOJ). We intend to vigorously defend against the DOJ s allegations. 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.

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 (a) claims from royalty owners for disputed royalty payments, (b) commercial disputes, (c) personal injury claims and (d) 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 20, 2013) of and positions held by our executive officers. Our executive officers serve at the discretion of our Board of Directors.

Name	Age	Position	Total Years of Service with Newfield
Lee K. Boothby	51	President, Chief Executive Officer and Chairman of the Board	13
Gary D. Packer	50	Executive Vice President and Chief Operating Officer	17
Terry W. Rathert	60	Executive Vice President and Chief Financial Officer	23
George T. Dunn	55	Senior Vice President Development	20
William D. Schneider	61	Senior Vice President Exploration	24
Daryll T. Howard	50	Vice President Rocky Mountains	16
John H. Jasek	43	Vice President Onshore Gulf Coast	13
Clay M. Gaspar	40	Vice President Mid-Continent	1
Kevin M. Robinson	57	Vice President Asia	15
Lawrence S. Massaro	49	Vice President Corporate Development	2
John D. Marziotti	49	General Counsel and Corporate Secretary	9
Brian L. Rickmers	44	Chief Commercial Officer	19
George W. Fairchild, Jr.	45	Controller and Assistant Corporate Secretary	1
Stephen C. Campbell	44	Vice President Investor Relations	13

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, he was Senior Vice President Acquisitions and Business Development. From 2002 2007, he was Vice President Mid-Continent. From 1999-2001, 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 LSU 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 Corporation in both the Rocky Mountains 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 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 completed the Management Program at Rice University.

George T. Dunn was promoted to Senior Vice President Development in September 2012, previously serving as Vice President Mid-Continent beginning 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 holds a degree in Petroleum Engineering from the Colorado School of Mines.

William D. Schneider was promoted to Senior Vice President Exploration in September 2012, previously serving as Vice President Gulf of Mexico and International beginning in February 2011. Prior to that, Mr. Schneider 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. He is an active member of the IPAA, where he served as Chairman of the International Committee and member of the Board of Directors from 1999 to 2009, and the American Petroleum Geologists.

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 Mountains 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.

Clay M. Gaspar joined Newfield in July of 2012 as Vice President Mid-Continent. Prior to joining Newfield, Mr. Gaspar spent 16 years with Anadarko Petroleum Corporation where he served as General Manager for Investor Relations from 2011 to 2012, General Manager, Business Advisor from 2009 to 2011 and General Manager, East Texas from 2007 to 2009. From 1996 to 2007, he served in various engineering and manager positions at Anadarko. Mr. Gaspar started his career with Mewbourne Oil Company as a production and drilling engineer where he worked from 1991 to 1996. He is a member of the Society of Petroleum Engineers and holds a B.S. in Petroleum Engineering from Texas A&M University and a M.S. in Petroleum and Geosciences Engineering from the University of Texas.

Kevin M. Robinson was promoted from Country Manager of Malaysia to Vice President Asia in September 2012. Mr. Robinson joined Newfield in 1997 from Huffco International L.L.C. and has held several roles within the Company s international businesses beginning with General Manager Malaysia. He was a founding member of the International team helping to lead Newfield s efforts in China, Australia and the United Kingdom. He moved to Malaysia in 2004 to open Newfield s Kuala Lumpur, Malaysia office. Mr. Robinson was promoted to Country Manager of Malaysia in 2009. Prior to 1997, Mr. Robinson worked as a Petroleum Geologist and Petroleum Geochemist throughout Southeast Asia, China, Australia and South America. He also worked with Core Labs Geoscience business in Southeast Asia where he helped take the company s business from a single geochemistry laboratory in Singapore to a number of integrated geoscience labs around Asia. Mr. Robinson holds a MSc. in Geochemistry from Leeds University England and a BSc. (Hons) in Geology from Sheffield University in England.

Lawrence S. Massaro joined Newfield as Vice President Corporate Development in March of 2011. Prior to joining Newfield, Mr. Massaro served as Managing Director at JP Morgan in its oil and gas investment banking group beginning in 2005 and was Vice President, Corporate Strategy and Business Development at Amerada Hess Corporation from 1995 through 2005. He also held the positions of Senior A&D at PG&E from 1992 to 1994 and Senior Production Engineer and Senior Reservoir Engineer at British Petroleum from 1985 through 1991. Mr. Massaro holds a degree in Petroleum Engineering from Texas A&M University and a M.S. in Business Administration from Southern Methodist University.

John D. Marziotti was promoted to General Counsel in August 2007 and was named Corporate 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 us, 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 being named Chief Commercial Officer, Mr. Rickmers served as Corporate Controller, Assistant Corporate Secretary and the Company s Principal Accounting Officer beginning in 2002. From December 1993 until 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.

George W. Fairchild, Jr. joined Newfield in August of 2012 as Controller and Assistant Corporate Secretary, serving as the Company s Principal Accounting Officer. Mr. Fairchild succeeded Brian L. Rickmers, who assumed a new role as Chief Commercial Officer in January 2012. Prior to joining Newfield, Mr. Fairchild served as Controller for Sheridan Production Company LLC, a privately-held oil and gas company, beginning in 2009 and was Vice President and Controller of Davis Petroleum Corporation, also a privately-held oil and gas company, from 2006 to 2009. Prior thereto, Mr. Fairchild was with Burlington Resources Inc., a publicly-held oil and gas company, serving as Senior Manager Accounting Policy & Research from 2001 to 2006 and Manager Internal Audit from 2000 to 2001. Before joining Burlington Resources Inc., he was with PricewaterhouseCoopers LLP from 1993 to 2000. Mr. Fairchild served in the U.S. Air Force from 1986 to 1990. He holds a B.B.A. in Accounting from the University of Texas and is a Certified Public Accountant.

Stephen C. Campbell was promoted to Vice President Investor Relations in December 2005, after serving as Newfield s Manager Investor Relations beginning in 1999. Prior to joining Newfield, Mr. Campbell was the Investor Relations Manager at Anadarko Petroleum Corporation from 1993 to 1999 and the Assistant Vice President of Marketing & Communications at United Way, Texas Gulf Coast from 1990 to 1993. He is a member of the National Investor Relations Institute and the Texas Public Relations Association. He holds a B.S. in Journalism from Texas A&M University.

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 (NYSE) 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
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	$ 42.47	$ 33.74
Second Quarter	36.66	25.01
Third Quarter	35.65	27.91
Fourth Quarter	34.79	23.56
2013:		
First Quarter (through February 20, 2013)	$ 30.50	$ 24.63

On February 20, 2013, the last reported sales price of our common stock on the NYSE was $24.75. As of that date, there were approximately 1,706 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 7 $^1/_8$% Senior Subordinated Notes due 2018, our 6 $^7/_8$% Senior Subordinated Notes due 2020, our 5 $^3/_4$% Senior Notes due 2022 and our 5 $^5/_8$% Senior Notes due 2024 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, 2012.

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, 2012	4,703	$31.62		
November 1 November 30, 2012	4,311	27.07		
December 1 December 31, 2012	1,895	24.45		

Total	10,909	$28.58

(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, 2007 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.

For 2012, we decided to update our peer group to be consistent with the peer group used by the Company to compare executive compensation and determine total stockholder return under its 2012 performance stock awards granted to executives.

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

Prior Peer Group. Our prior peer group (first used in our 2011 Report on Form 10-K) consisted 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 Corporation.

Comparison of 5 Year Cumulative Total Return

Total Return Analysis		**12/31/2007**		**12/31/2008**		**12/31/2009**		**12/31/2010**		**12/31/2011**		**12/31/2012**
Newfield Exploration Company	$	100.00	$	37.47	$	91.50	$	136.81	$	71.58	$	50.80
Old Peer Group	$	100.00	$	55.76	$	90.40	$	99.43	$	96.03	$	100.84
New Peer Group	$	100.00	$	53.56	$	86.71	$	95.48	$	88.89	$	88.93
S&P 500	$	100.00	$	63.01	$	79.67	$	91.67	$	93.61	$	108.59

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,				
	2012	2011	2010	2009	2008(1)
	(In millions, except per share data)				
Statement of Operations Data:					
Oil, gas and NGL revenues	$ 2,567	$ 2,471	$ 1,883	$ 1,338	$ 2,225
Net income (loss)	(1,184)	539	523	(542)	(373)
Earnings (loss) per share:					
Basic					
Net income (loss)	(8.80)	4.03	3.97	(4.18)	(2.88)
Diluted					
Net income (loss)	(8.80)	3.99	3.91	(4.18)	(2.88)
Weighted-average number of shares outstanding for basic earnings (loss) per share	135	134	132	130	129
Weighted-average number of shares outstanding for diluted earnings (loss) per share	135	135	134	130	129
Cash Flow Data:					
Net cash provided by operating activities	$ 1,147	$ 1,589	$ 1,630	$ 1,578	$ 854
Net cash used in investing activities	(1,159)	(2,236)	(1,951)	(1,356)	(2,253)
Net cash provided by (used in) financing activities	24	684	282	(168)	1,173
Balance Sheet Data (at end of period):					
Total assets	$ 7,912	$ 8,991	$ 7,494	$ 6,254	$ 7,305
Long-term debt	3,045	3,006	2,304	2,037	2,213
Proved Reserves Data (at end of period):					
Crude Oil and Condensate (MMBbls)	237	247	198	166	138
Natural gas (Bcf)	1,755	2,333	2,492	2,605	2,110
NGLs (MMBbls)	37	16	6	3	2
Total proved reserves (Bcfe)	3,398	3,911	3,712	3,616	2,950
Present value of estimated future after-tax net cash flows	$ 4,436	$ 5,981	$ 4,754	$ 2,864	$ 2,929

(1) Effective December 31, 2009, we adopted revised authoritative accounting and disclosure requirements of the Financial Accounting Standards Board and the SEC for oil and gas reserves. As a result, certain 2008 disclosures and amounts are not on a basis comparable to other periods presented.

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 Gulf Coast. Internationally, we focus on offshore oil developments in Malaysia and China. In February 2013, we initiated a process to evaluate strategic alternatives with respect to our international businesses.

To maintain and grow our production and cash flows, we must continue to develop existing proved reserves and locate or acquire new oil and natural gas reserves to replace those reserves being produced. Our revenues, profitability and future growth depend substantially on prevailing prices for oil, natural gas and NGLs and on our ability to find, develop and acquire oil and natural gas reserves that are economically recoverable. Prices for oil, natural gas and NGLs fluctuate widely and affect:

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

We prepare our financial statements in conformity with generally accepted accounting principles, which require 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 natural gas reserves. In addition, 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, including salaries, benefits and other internal costs directly attributable to these assets, are capitalized. The net capitalized costs for our oil and gas properties may not exceed the present value of estimated future net cash flows from proved reserves. If these costs exceed the limit, we are required to charge the excess to earnings, also referred to as a ceiling test writedown. As of December 31, 2012, the unamortized net capitalized costs of our domestic oil and gas properties exceeded the ceiling amount by approximately $1.5 billion ($948 million, after-tax). The risk of incurring a ceiling test writedown increases when commodity prices are low for a sustained period of time. If there are further declines in SEC pricing, we may be required to record a ceiling test writedown in future periods.

Results of Operations

Revenues. Our revenues are primarily derived from the sale of oil, natural gas and NGLs and do not include the effects of the settlements of our derivative positions. 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 offshore operations in Malaysia and China is produced into FPSOs or onshore storage terminals, 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.

During the year ended December 31, 2012, our revenues were up $96 million, or 4%, over 2011 and reflect our continued focus on increasing our liquids production and allowing our natural gas production to decline. Oil production was up 24% in 2012, and when combined with slightly higher prices, added an additional $431 million compared to 2011. Substantially offsetting the uplift in revenues from oil were lower gas prices and volumes that resulted in $326 million less gas revenues in 2012 compared to 2011. Increased NGL production of 30% was more than offset by a 30% decline in NGL prices during the year. Revenues of $2.5 billion for 2011 were 31% higher than 2010. For 2011, approximately half of the increase in revenue was due to higher average realized oil prices and half of the increase resulted from increased oil production. The following table reflects our production and average realized commodity prices for each of the years ended December 31.

	2012	2011	2010
Production:(1)(2)			
Domestic:			
Crude oil and condensate (MBbls)	11,988	10,939	8,498
Natural gas (Bcf)	143.5	175.1	186.9
NGLs (MBbls)	2,608	2,004	1,518
Total (Bcfe)	231.1	252.7	247.0
International:			
Crude oil and condensate (MBbls)	9,914	6,715	6,057
Natural gas (Bcf)	1.2	0.1	
Total (Bcfe)	60.7	40.4	36.3
Total:			
Crude oil and condensate (MBbls)	21,902	17,654	14,555
Natural gas (Bcf)	144.7	175.2	186.9
NGLs (MBbls)	2,608	2,004	1,518
Total (Bcfe)	291.8	293.1	283.3
Average Realized Prices:(2)(3)			
Domestic:			
Crude oil and condensate (per Bbl)	$ 83.99	$ 85.68	$ 69.03
Natural gas (per Mcf)	2.64	4.05	4.09
NGLs (per Bbl)	31.26	44.42	44.74
Natural gas equivalent (per Mcfe)	6.35	6.89	5.78
International:			
Crude oil and condensate (per Bbl)	$ 109.67	$ 108.51	$ 75.27
Natural gas (per Mcf)	3.89	3.95	
Natural gas equivalent (per Mcfe)	18.01	18.06	12.54
Total:			
Crude oil and condensate (per Bbl)	$ 95.62	$ 94.36	$ 71.62
Natural gas (per Mcf)	2.65	4.05	4.09
NGLs (per Bbl)	31.26	44.42	44.74
Natural gas equivalent (per Mcfe)	8.77	8.43	6.65

(1) Represents volumes lifted and sold regardless of when produced. Excludes natural gas produced and consumed in operations of 7.8 Bcfe in 2012, 6.8 Bcfe in 2011 and 5.3 Bcfe in 2010.

(2) Historically, we reported natural gas liquid (NGL) volumes combined with oil and condensate production. Effective in our Form 10-K for the period ended December 31, 2012, we began reporting NGL production separately from crude oil and condensate production. As such, all production volumes and average realized prices for periods prior to 2012 have been reclassified for comparability between periods.

(3) Had we included the effects of hedging contracts not designated for hedge accounting, the average realized price for total natural gas would have been $3.57, $5.43 and $5.62 per Mcf for the years ended December 31, 2012, 2011 and 2010, respectively; and the average crude oil realized price would have been $95.68, $91.70 and $81.32 per Bbl for 2012, 2011 and 2010, respectively. We did not have any hedging contracts associated with NGL production in 2012, 2011 or 2010.

Domestic Production. Our 2012 domestic oil, natural gas and NGL production, stated on a natural gas equivalent basis, decreased 9% compared to 2011 production. The decrease relates primarily to the sale of assets in the Gulf of Mexico and natural declines in our natural gas assets due to lack of investment as our investments have been focused on oil and liquids projects. Our domestic oil and liquids production increased approximately 13% in 2012 when compared to the prior year.

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 Mountains and Mid-Continent regions as a result of continued successful development drilling efforts, partially offset by production decreases in our onshore Gulf Coast region and Gulf of Mexico deepwater operations due to natural field decline and weather- and equipment-related delays.

International Production. Our 2012 international oil production increased by 48% over 2011 levels primarily due to an increase of 53% in Malaysia production resulting from continued successful drilling on our East Belamut field, as well as full-year production on our East Piatu and Puteri fields, brought online during the fourth quarter of 2011. 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 from our East Piatu and East Belamut fields and the timing of liftings.

Operating Expenses.

Year ended December 31, 2012 compared to December 31, 2011

The following table compares information about our operating expenses between the following periods:

	Unit-of-Production Year Ended December 31, (Per Mcfe)		Percentage Increase (Decrease)	Total Amount Year Ended December 31, (In millions)		Percentage Increase (Decrease)
	2012	2011		2012	2011	
Domestic:						
Lease operating	$ 1.76	$ 1.42	24%	$ 406	$ 358	13%
Production and other taxes	0.29	0.27	7%	67	68	(2)%
Depreciation, depletion and amortization	2.96	2.46	20%	683	621	10%
General and administrative	0.91	0.71	28%	211	180	17%
Ceiling test impairment	6.44		n/a	1,488		n/a
Other	0.06		n/a	15		n/a
Total operating expenses	12.42	4.85	156%	2,870	1,227	134%
International:						
Lease operating	$ 1.79	$ 2.36	(24)%	$ 108	$ 95	14%
Production and other taxes	4.57	6.49	(30)%	277	262	6%
Depreciation, depletion and amortization	4.48	3.60	24%	272	146	87%
General and administrative	0.12	0.13	(8)%	7	5	30%
Total operating expenses	10.95	12.58	(13)%	664	508	31%
Total:						
Lease operating	$ 1.76	$ 1.55	14%	$ 514	$ 453	13%
Production and other taxes	1.18	1.13	4%	344	330	4%
Depreciation, depletion and amortization	3.27	2.62	25%	955	767	25%
General and administrative	0.75	0.63	19%	218	185	18%
Ceiling test impairment	5.10		n/a	1,488		n/a
Other	0.05		n/a	15		n/a
Total operating expenses	12.11	5.92	105%	3,534	1,735	104%

Domestic Operations. Excluding the ceiling test writedown, the increase in our depletion rate due to price related downward reserve revisions and the impact of selling our offshore Gulf of Mexico assets, our operating expenses increased 21%. The components of the significant period-to-period change are as follows:

Lease operating expenses (LOE) include 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. Recurring LOE increased $0.05 per Mcfe to $0.93 per Mcfe. The increase was due to higher compression, fuel, electricity, and rental equipment costs coupled with declining natural gas production in our Mid-Continent region. Partially offsetting this increase was improved recurring LOE per unit in our Rocky Mountain and Onshore Gulf Coast regions. Increases in our non-recurring LOE of $42 million accounted for 87% of the increase in total domestic LOE primarily due to the following:

increased workover activity was the primary factor resulting in a $14 million increase in non-recurring LOE in our Rocky Mountain region;

restimulation of several wells in our effort to improve performance was the leading driver of the $13 million non-recurring LOE increase in our Mid-Continent region;

repairs to plugged flow lines in our deepwater Gulf of Mexico operations, which were subsequently sold in the fourth quarter of 2012, was the primary driver of an additional increase of $12 million in non-recurring LOE; and

Transportation costs related to firm transportation agreements in our Mid-Continent region accounted for $0.08 per Mcfe of the increase.

Our average depreciation, depletion and amortization (DD&A) rate increased $0.50 per Mcfe during 2012 and reflects our continued focus on oil and liquids rich gas developments that are more capital intensive on a per Mcfe basis as compared to natural gas developments. While our average DD&A rate in 2011 was $2.46, our rate for the fourth quarter of 2011 was $2.58. During 2012, this rate increased as the additional cost of each Mcfe added was higher. In addition, the full year average rate was negatively impacted by downward reserve revisions (primarily due to natural gas price declines) combined with the net impact of selling our remaining Gulf of Mexico assets. Without these items, our average DD&A rate for the year ended December 31, 2012 would have been $2.89.

General and administrative (G&A) expense per Mcfe increased during 2012 primarily due to employee-related expenses associated with our domestic work force combined with lower domestic production. During 2012, we capitalized $95 million ($0.41 per Mcfe) of direct internal costs as compared to $83 million ($0.33 per Mcfe) during 2011.

In the fourth quarter of 2012 we recorded a ceiling test writedown of $1.5 billion ($6.44 per Mcfe) due to a net decrease in the discounted value of our proved reserves. The primary reason for the change in value was negative price-related reserve revisions as a result of a 33% decrease in the natural gas SEC pricing.

Other expenses of $15 million ($0.06 per Mcfe) include a writedown of $8 million of subsea wellhead inventory that was not included in the sale of our Gulf of Mexico assets and contract termination costs of $6 million in consideration of other services.

International Operations. Our international operating expenses for 2012, stated on a Mcfe basis, decreased 13% over 2011. The components of the period-to-period change are as follows:

LOE per Mcfe decreased by 24% ($0.57 per Mcfe) primarily due to lower non-recurring workover activity during 2012. Recurring LOE was essentially flat on a per unit basis with a decrease of $0.02 per Mcfe, or 1%.

Production and other taxes per Mcfe decreased by 30% due to an overall change in the mix of production that was lifted and sold from the various PSCs in Malaysia including the fields brought online during the fourth quarter of 2011. The production tax rates per barrel of oil lifted and sold from these newer developments are lower, per the terms of our PSCs, while we recover our costs associated with these developments.

Total DD&A expense increased 87% in 2012 compared to 2011 due to a combination of an increase in the average DD&A rate and a 50% increase in production during 2012. Our average annual DD&A rate per Mcfe increased 24% when compared to the average annual 2011 rate. The average annual 2012 rate when compared to the end of year 2011 rate of $4.17 was 7% higher and was primarily due to the costs of two unsuccessful wells offshore Malaysia, which increased the amount subject to depletion without any associated reserve additions.

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

The following table presents information comparing our operating expenses for the following periods:

	Unit-of-Production Year Ended December 31,		Percentage Increase	Total Amount Year Ended December 31,		Percentage Increase
	2011	**2010**	**(Decrease)**	**2011**	**2010**	**(Decrease)**
	(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%
Other		0.03	(100)%		7	(100)%
Total operating expenses	4.85	3.97	22%	1,227	980	25%
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%
Other		0.03	(100)%		7	(100)%
Total operating expenses	5.92	4.44	33%	1,735	1,259	38 %

Domestic Operations. Our domestic operating expenses for 2011, stated on a Mcfe basis, increased 22% over those for 2010. The components of the significant period-to-period change are as follows:

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 Mountains region 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 region throughout 2010.

Production and other taxes per Mcfe increased due to a 21% increase in realized oil prices in 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 DD&A rate. The increase in total DD&A expense is related to the increase in the DD&A rate, coupled with a slight increase in our production volumes during 2011 compared to 2010.

G&A expense per Mcfe increased during 2011 due to employee-related expenses associated with the growth we experienced in our domestic workforce and approximately $7 million of legal expenses related to litigation in which we were 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) related to certain claims related to the bankruptcy proceedings associated with TXCO Resources Inc.

International Operations. Our international operating expenses for 2011, stated on a Mcfe basis, increased 63% over 2010. The components of the 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 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 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 increased due to an 11% increase in volumes during 2011 compared to 2010 combined with an increase in our ratio of costs subject to depletion over proved reserves in the fourth quarter 2011 related to our new offshore Malaysian developments.

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

	2012	2011 (In millions)	2010
Gross interest expense:			
Credit arrangements	$ 9	$ 11	$ 3
Senior notes	73	11	2
Senior subordinated notes	122	152	149
Other	1	1	2
Total gross interest expense	205	175	156
Capitalized interest	(68)	(82)	(58)
Net interest expense	$ 137	$ 93	$ 98

The increase in gross interest expense in 2012 as compared to 2011 primarily resulted from the September 2011 issuance of $750 million aggregate principal amount of 5 3/4% Senior Notes due 2022, as well as the June 2012 issuance of $1 billion aggregate principal amount of 5 5/8% Senior Notes due 2024, partially offset by the redemption in April 2012 of our $325 million 6 5/8% Senior Subordinated Notes due 2014 and in July 2012 of our $550 million 6 5/8% Senior Subordinated Notes due 2016. The increase in gross interest expense in 2011 as compared to 2010 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. See Note 8, Debt, to our consolidated financial statements in Item 8 of this report.

Interest expense associated with oil and gas properties excluded from amortization is capitalized into oil and gas properties. Capitalized interest decreased in 2012 as compared to 2011, due to a reduction in our average balance of oil and gas properties excluded from amortization. As a result of the October 2012 sale of our Gulf of Mexico assets, unproved oil and gas properties that had been previously excluded from amortization were removed from such classification. Capitalized interest increased in 2011 as compared to 2010 due to an increase in the average balance of oil and gas properties excluded from amortization, primarily resulting from the acquisition of assets in the Uinta Basin of Utah.

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

Taxes. The effective tax rates for the years ended December 31, 2012, 2011 and 2010 were (20%), 36% and 37%, 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 2012 was affected by our decision to repatriate international earnings, use foreign tax credits (FTCs), a valuation allowance for FTCs and the recording of a valuation allowance related to our deferred tax asset in Malaysia. Please see the discussion and tables in Note 9, Income Taxes, to our consolidated financial statements in Item 8 of this report, which are incorporated herein by reference.

Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices; the timing, amount and location of future production; 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, natural gas and NGLs 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, which includes cash flows from operations and if applicable, non-strategic asset sales. Approximately 84% of our expected 2013 domestic oil and gas production (excluding NGLs) supporting the current 2013 capital budget estimate is hedged. Our 2013 capital budget, excluding estimated capitalized interest and overhead of $182 million, is expected to be between $1.7 $1.9 billion and focuses on projects with higher return on investment, which we believe generate and lay the foundation for oil production growth in 2014 and thereafter. Of the total 2013 capital budget, approximately $1.4 $1.5 billion will be allocated to our domestic business. Substantially all of the 2013 budget is allocated to oil or liquids-rich projects.

Actual capital expenditure levels may vary significantly due to many factors, including drilling results, oil, natural gas and NGL prices, industry conditions, the prices and availability of goods and services, the extent to which properties are acquired or non-strategic assets sold. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. We believe we have the operational flexibility to react quickly with our capital expenditures to changes in circumstances and our cash flows from operations.

During 2012, we:

- received proceeds from the sale of non-strategic assets of $630 million;
- issued $1 billion aggregate principal of 5 $^{5}/_{8}$% Senior Notes due 2024;
- repurchased our $325 million aggregate principal of 6 $^{5}/_{8}$% Senior Subordinated Notes due 2014; and
- repurchased our $550 million aggregate principal of 6 $^{5}/_{8}$% Senior Subordinated Notes due 2016.

We used a portion of the proceeds from the $1 billion Senior Notes offering combined with the proceeds from our non-strategic asset sale program to reduce borrowings outstanding under our credit arrangements, as well as redeem our 6 $^{5}/_{8}$% Senior Subordinated Notes due 2016. As a result, at December 31, 2012, we had available borrowing capacity of $1.4 billion under our credit arrangements. In October 2012, we closed the sale of our remaining assets in the Gulf of Mexico to W&T Offshore, Inc. for approximately $208 million, subject to customary post-closing adjustments. We expect to substantially fund our 2013 capital program with cash flows from operations, proceeds from non-strategic asset sales during the year and available borrowing capacity under our credit arrangements. We believe that the Company s liquidity position and our ability to generate cash flows from our asset portfolio will be adequate to fund 2013 operations.

We continue to hold auction rate securities with a fair value of $36 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. We maintain a revolving credit facility of $1.25 billion that matures in June 2016, as well as money market lines of credit of $145 million, for a total borrowing capacity of $1.4 billion at December 31, 2012. Our long-term debt includes senior and senior subordinated notes which total $3.05 billion. At December 31, 2012, we had no scheduled maturities of Senior Notes or Senior Subordinated Notes until 2018. For a more detailed description of the terms of our credit arrangements and senior and senior subordinated notes, please see Note 8, Debt, to our consolidated financial statements in Item 8 of this report, which are incorporated herein by reference.

At February 20, 2013, we had no letters of credit outstanding under our credit facility. We had outstanding borrowings of $65 million under our credit facility. Our available borrowing capacity under our credit arrangements was approximately $1.3 billion, and we had $2 million in other undrawn letters of credit outstanding.

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.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements, changes in the fair value of our outstanding commodity derivative instruments as well as the timing of receiving reimbursement of amounts paid by us for the benefit of joint venture partners. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. We anticipate that our 2013 capital investment levels will exceed our estimate of cash flows from operations. We expect to sell non-strategic assets and use available capacity under our credit arrangements to fund any shortfall.

At December 31, 2012 and 2011, we had negative working capital of $93 million and $157 million, respectively. The changes in our working capital are primarily a result of the timing of the collection of receivables, changes in the fair value of our derivative positions, the timing of crude oil liftings in our international operations, 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 our primary source of capital and liquidity and are primarily affected by sale of our oil, natural gas and NGLs, as well as commodity prices, net of the effects of settlements of our derivative contracts and changes in working capital. We sell substantially all of our oil, gas and NGLs 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 24-36 months. As of December 31, 2012, we had no open derivative contracts for NGLs. 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 $1.1 billion in 2012 and $1.6 billion in 2011 and 2010. The changes in cash flow from operations in 2012 compared to 2011 was primarily due to changes in operating assets and liabilities coupled with a decrease in our after tax cash margin as a result of a significant increase in cash taxes in Malaysia.

Cash Flows from Investing Activities. Net cash used in investing activities for 2012 was $1.2 billion compared to $2.2 billion for 2011.

During 2012, we:

- spent approximately $1.8 billion for additions to property and equipment (including $9 million for acquisitions of oil and gas properties); and
- received proceeds of $630 million from sales of oil and gas properties.

During 2011, we:

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

Cash Flows from Financing Activities. Net cash provided by financing activities for 2012 was $24 million compared to $684 million for 2011.

During 2012, we:

- Reduced our borrowings under our revolving credit facility by $86 million;
- issued $1 billion aggregate principal amount of $5\,^5/_8$% Senior Notes due 2024 at par and paid approximately $10 million in associated debt issue costs;
- repaid our $325 million and $550 million aggregate principal amount of $6\,^5/_8$% Senior Subordinated Notes due 2014 and 2016, respectively;

- received proceeds of $2 million from the issuances of shares of our common stock upon the exercise of stock options; and
- repurchased $11 million of our common stock surrendered by employees to pay tax withholding upon the vesting of restricted stock and restricted stock unit awards.

During 2011, we:

- Reduced our borrowings under our revolving credit facility arrangements by $49 million;
- issued $750 million aggregate principal amount of 5 $^3/_4$% Senior Notes due 2022 at 99.956% of par and paid approximately $8 million in associated debt issue costs;

paid approximately $8 million in debt issue costs associated with our new revolving credit facility;

received proceeds of $13 million from the 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.

Capital Expenditures. Our capital investments of $1.9 billion for 2012 decreased 14% from our capital investments of $2.2 billion during 2011. These amounts exclude negligible acquisitions during 2012 and $321 million in 2011, and recorded asset retirement obligations of $9 million and $33 million in the respective years. Of the total $1.9 billion invested during 2012, we invested $1.3 billion in domestic exploitation and development, $239 million in domestic exploration (exclusive of exploitation and leasehold activity), $67 million in leasing domestic proved and unproved property (leasehold) and $253 million outside the United States.

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 $2.2 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), $131 million in leasing domestic proved and unproved property (leasehold) and $314 million outside the United States.

We have budgeted between $1.7 $1.9 billion of planned capital investments in 2013. The planned budget excludes estimated capitalized interest and overhead of approximately $182 million, as well as any acquisitions. Substantially all of the 2013 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, natural gas and NGL prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, at times we have increased our capital budget 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.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of December 31, 2012.

	Total	**Less than 1 Year**	**1-3 Years (In millions)**	**4-5 Years**	**More than 5 Years**
Debt:					
5 $^{3}/_{4}$% Senior Notes due 2022	$ 750	$	$	$	$ 750
5 $^{5}/_{8}$% Senior Notes due 2024	1,000				1,000
7 $^{1}/_{8}$% Senior Subordinated Notes due 2018	600			600	
6 $^{7}/_{8}$% Senior Subordinated Notes due 2020	700				700
Total debt	3,050			600	2,450
Other obligations:					
Interest payments	1,681	191	571	359	560
Net derivative (assets) liabilities	(121)	(119)	(2)		
Asset retirement obligations	142	10	32	14	86
Operating leases and other[(1)]	564	394	114	28	28
Firm transportation	523	78	226	134	85
Oil and gas activities[(2)]	132				
Total other obligations	2,921	554	941	535	759
Total contractual obligations	$ 5,971	$ 554	$ 941	$ 1,135	$ 3,209

(1) Includes agreements for office space, platform construction, drilling rigs and other equipment, as well as certain service contracts. The majority of these obligations are related to contracts for platform construction 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.

(2) 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, 2012, these work-related commitments totaled $132 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. However, in the event that we are unable to meet our crude oil volume delivery commitments, we would incur deficiency fees ranging from $2.55 to $6.50 per barrel. See Items 1 and 2, *Business and Properties* for a description of our production and proved reserves. As of December 31, 2012, our delivery commitments through 2024 were as follows:

	Total	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
Natural gas (MMMBtus)	6,570	6,570			
Oil (MBbls)[(1)]	122,739	5,323	37,088	27,740	52,588

(1) Our oil delivery commitments include a particular commitment with a Salt Lake City, Utah refiner. This delivery commitment will begin upon the refiner completing the expansion of their facility, which is expected in late 2014 or early 2015. Our delivery commitment is to deliver approximately 20,000 barrels of oil per day over a 10-year period. This delivery commitment represents approximately 50% of our committed oil volumes for each of the years 2015 through 2019, increases to 77% in 2020, and is 100% of our commitment through 2024.

Oil and Gas Hedging

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 future oil and gas production for the next 24-36 months. As of December 31, 2012, we had no outstanding derivative contracts related to our NGL production. 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. We do not use derivative instruments for trading purposes. For a further discussion of our hedging activities, see *Critical Accounting Policies and Estimates Commodity Derivative Activities* below and *Oil, Natural Gas and NGL Prices* in Item 7A of this report. Please see the discussion and tables in Note 4, Derivative Financial Instruments, and Note 7, Fair Value Measurements, to our consolidated financial statements in Item 8 of this report for additional information regarding the accounting applicable to our oil and gas derivative contracts, a listing of open contracts and the estimated fair market value of those contracts as of December 31, 2012.

Between January 1, 2013 and February 20, 2013, we entered into additional derivative contracts as set forth below.

Natural Gas

		NYMEX Contract Price Per MMBtu				
			Collars			
			Floors		Ceilings	
Period and Type of Contract	Volume in MMMBtus	Swaps (Weighted Average)	Range	Weighted Average	Range	Weighted Average
January 2014 December 2014						
Price swap contracts	10,950	$ 4.04				
January 2015 December 2015						
Price swap contracts	21,900	4.23				
Collar contracts	5,745		$ 4.00	$ 4.00	$ 4.60	$ 4.60

Oil

		NYMEX Contract Price per Bbl
Period and Type of Contract	Volume in MBbls	Swaps (Weighted Average)
April 2014 June 2014		
Price swap contracts	137	$ 94.23
July 2014 September 2014		
Price swap contracts	92	92.78
October 2014 December 2014		
Price swap contracts	184	92.20
January 2015 December 2015		
Price swap contracts	1,095	90.40

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 costs *require 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 a two-step test that compares the carrying value of the properties to the undiscounted cash flows to see if an impairment is required. If required, the impairment is the difference between the carrying value of individual oil and gas properties and their estimated fair value using forward looking prices. 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 SEC pricing, costs in effect at year-end and a 10% discount rate.

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 cost 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 exploration and development 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 less accumulated amortization, plus an estimate of our future development costs and estimated dismantlement and abandonment costs, net of salvage values 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 SEC pricing 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, gas and NGL 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, gas and NGL 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, 2012 would have required a change in the estimate of our domestic proved reserves of approximately 3%, or 100 Bcfe. To change our Malaysia DD&A rate by $0.10 per Mcfe for the year ended December 31, 2012 would have required a change in the estimate of our proved reserves in Malaysia of approximately 2%, or 2 Bcfe. To change our China DD&A rate by $0.10 per Mcfe for the year ended December 31, 2012 would have required a change in the estimate of our proved reserves in China of approximately 2%, or 3 Bcfe.

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 of oil and gas properties exceed the applicable 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 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, gas and NGL reserves is calculated based on SEC pricing 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, 2012, the ceiling value of our reserves was calculated based upon SEC pricing of $2.76 per MMBtu for natural gas and $94.84 per barrel for oil. Using these prices, the cost center ceiling at December 31, 2012 was below the net capitalized costs of our domestic oil and gas properties, resulting in a ceiling test writedown of approximately $1.5 billion.

At December 31, 2012, the Malaysia and China cost center ceilings exceeded the net capitalized costs of oil and gas properties by approximately $72 million and $376 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 average oil price declined approximately 31% and 62%, respectively, from prices used at December 31, 2012.

Given the fluctuation of oil, natural gas and NGL prices, it is reasonably possible that the estimated discounted future net cash flows from our proved reserves will change in the near term. If commodity prices 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 related seismic data, wells currently drilling 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 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, 2012, we had a total of approximately $1.5 billion of costs excluded from the amortization base of our respective full cost pools, the majority of which related to our domestic full cost pool. Inclusion of some or all of our domestic unevaluated property costs in our domestic full cost pool, without adding any associated reserves, would have resulted in a larger ceiling test writedown. The same test applied to our international business units resulted in an excess of the cost center ceilings over the carrying value of our oil and gas properties for each of our international full cost pools. Holding all other factors constant, including all of our unevaluated property costs in our Malaysia and China amortization bases would not have resulted in a ceiling test writedown for either full cost pool.

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, 2012 would have required a change in the estimate of our domestic future development and abandonment costs of approximately 8%, or $318 million. To change our Malaysia DD&A rate by $0.10 per Mcfe for the year ended December 31, 2012 would have required a change in the estimate of our future development and abandonment costs in Malaysia of approximately 28%, or $10 million. To change our China DD&A rate by $0.10 per Mcfe for the year ended December 31, 2012 would have required a change in the estimate of our future development and abandonment costs in China of approximately 6%, or $12 million.

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 natural 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 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 natural gas reserves and unproved properties is subject to the cost center ceiling as described under *Full Cost Ceiling Limitation* above. The accounting standard for business combinations establishes 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.

Commodity Derivative Activities. Under accounting rules, we may elect to designate certain derivative contracts that qualify for hedge accounting as cash flow hedges against the price that we will receive for our future oil and gas production. We do not designate 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 have in the past experienced, and are likely in the future to experience non-cash volatility in our reported earnings during periods of commodity price volatility. As of December 31, 2012, we had net derivative assets of $121 million, of which 50%, based on total hedged volumes, was measured based upon our valuation model (i.e. Black-Scholes) and, as such, is classified as a Level 3 fair value measurement. 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. As a result, the value of these contracts at their respective settlement dates could be significantly different than the fair value as of December 31, 2012. 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 grant or modification date 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 stock units that are accounted for under the liability method which requires us 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 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 regarding offsetting assets and liabilities 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 effective for interim and annual periods beginning on or after December 15, 2011. We adopted the provisions for the quarter ended March 31, 2012. 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 required, for Level 3 fair value measurements, disclosure of 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 adopted the provisions for the quarter ended March 31, 2012. Adopting the additional fair value measurement and disclosure requirements did not have a material impact on our financial position or results of operations.

Regulation

Exploration and development and the production and sale of oil, gas and NGLs 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, natural gas and NGL prices, interest rates and foreign currency exchange rates as discussed below.

Oil, Natural Gas and NGL Prices

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 24-36 months to reduce our exposure to fluctuations in oil and natural gas prices. As of December 31, 2012, we had no outstanding derivative contracts related to our NGL production. 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 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 benefits 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. At December 31, 2012, seven of our 15 counterparties accounted for approximately 85% of our estimated future hedged production with no single counterparty accounting for more than 25% of that production. For a further discussion of our hedging activities, see the information under the caption Oil and Gas Hedging and Critical Accounting Policies and Estimates 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

We consider our interest rate exposure to be minimal because 100% of our obligations were at fixed rates as of December 31, 2012. A 10% increase in LIBOR would not impact our interest cost on debt outstanding as of December 31, 2012, but would affect the fair value of outstanding debt, as well as interest cost associated with future debt issuances or borrowings under our revolving credit facility.

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, 2012.

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

NEWFIELD EXPLORATION COMPANY

TABLE OF CONTENTS

CONSOLIDATED FINANCIAL STATEMENTS

AND SUPPLEMENTARY INFORMATION

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, 2012.

The effectiveness of our internal control over financial reporting as of December 31, 2012 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

The Woodlands, Texas

February 26, 2013

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 operations, 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, 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.

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.

Houston, Texas

February 26, 2013

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEET

(In millions, except share data)

	December 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 88	$ 76
Accounts receivable	452	407
Inventories	132	90
Derivative assets	125	129
Other current assets	69	73
Total current assets	866	775
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,550 and $1,965 were excluded from amortization at December 31, 2012 and 2011, respectively)	14,346	14,526
Less accumulated depreciation, depletion and amortization	(7,444)	(6,506)
Total property and equipment, net	6,902	8,020
Derivative assets	17	61
Long-term investments	58	52
Deferred taxes	24	28
Other assets	45	55
Total assets	$ 7,912	$ 8,991
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 69	$ 112
Accrued liabilities	801	687
Advances from joint owners	31	45
Asset retirement obligations	10	10
Derivative liabilities	6	50
Deferred taxes	42	28
Total current liabilities	959	932
Other liabilities	47	44
Derivative liabilities	15	3
Long-term debt	3,045	3,006
Asset retirement obligations	132	135
Deferred taxes	934	951
Total long-term liabilities	4,173	4,139
Commitments and contingencies (Note 12)		
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, 2012 and 2011; 136,530,907 and 136,379,381 shares issued at December 31, 2012 and 2011, respectively)	1	1

Additional paid-in capital	1,522	1,495
Treasury stock (at cost, 1,216,591 and 1,694,623 shares at December 31, 2012 and 2011, respectively)	(36)	(50)
Accumulated other comprehensive loss	(7)	(10)
Retained earnings	1,300	2,484
Total stockholders equity	2,780	3,920
Total liabilities and stockholders equity	$ 7,912	$ 8,991

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

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF OPERATIONS

(In millions, except per share data)

	Year Ended December 31,		
	2012	**2011**	**2010**
Oil, gas and NGL revenues	$ 2,567	$ 2,471	$ 1,883
Operating expenses:			
Lease operating	514	453	326
Production and other taxes	344	330	126
Depreciation, depletion and amortization	955	767	644
General and administrative	218	185	156
Ceiling test impairment	1,488		
Other	15		7
Total operating expenses	3,534	1,735	1,259
Income (loss) from operations	(967)	736	624
Other income (expense):			
Interest expense	(205)	(175)	(156)
Capitalized interest	68	82	58
Commodity derivative income	120	195	316
Other	(4)	2	(13)
Total other income (expense)	(21)	104	205
Income (loss) before income taxes	(988)	840	829
Income tax provision:			
Current	195	93	59
Deferred	1	208	247
Total income tax provision	196	301	306
Net income (loss)	$ (1,184)	$ 539	$ 523
Earnings (loss) per share			
Basic	$ (8.80)	$ 4.03	$ 3.97
Diluted	$ (8.80)	$ 3.99	$ 3.91
Weighted-average number of shares outstanding for basic earnings (loss) per share	135	134	132
Weighted-average number of shares outstanding for diluted earnings (loss) per share	135	135	134

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,		
	2012	**2011**	**2010**
Net income (loss)	$ (1,184)	$ 539	$ 523
Other comprehensive income (loss):			
Unrealized gain on investments, net of tax of ($1) for each of the years ended December 31, 2012 and 2011	3	3	
Unrealized loss on post-retirement benefits, net of tax		(1)	(1)
Other comprehensive income (loss), net of tax	3	2	(1)
Comprehensive income (loss)	$ (1,181)	$ 541	$ 522

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				Accumulated Other	
	Shares	Amount	Shares	Amount	Additional Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Total Stockholders Equity
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
Issuances of common stock	0.1				2			2
Stock-based compensation					46			46
Treasury stock, net			0.5	14	(21)			(7)
Net loss						(1,184)		(1,184)
Other comprehensive income, net of tax							3	3
Balance, December 31, 2012	136.5	$ 1	(1.2)	$ (36)	$ 1,522	$ 1,300	$ (7)	$ 2,780

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,		
	2012	**2011**	**2010**
Cash flows from operating activities:			
Net income (loss)	$ (1,184)	$ 539	$ 523
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	955	767	644
Deferred tax provision	1	208	247
Stock-based compensation	35	29	22
Commodity derivative income	(120)	(195)	(316)
Cash receipts on derivative settlements, net	135	195	456
Ceiling test impairment	1,488		
Other non-cash charges	19	6	14
Changes in operating assets and liabilities:			
Increase in accounts receivable	(70)	(24)	(15)
(Increase) decrease in inventories	(35)	(16)	3
(Increase) decrease in other current assets	5	(12)	65
(Increase) decrease in other assets	7	(7)	(22)
Increase (decrease) in accounts payable and accrued liabilities	(77)	120	11
Decrease in advances from joint owners	(14)	(6)	
Increase (decrease) in other liabilities	2	(15)	(2)
Net cash provided by operating activities	1,147	1,589	1,630
Cash flows from investing activities:			
Additions to oil and gas properties	(1,758)	(2,311)	(1,635)
Acquisitions of oil and gas properties	(9)	(304)	(313)
Proceeds from sales of oil and gas properties	630	406	12
Additions to furniture, fixtures and equipment	(22)	(29)	(23)
Redemptions of investments		2	8
Net cash used in investing activities	(1,159)	(2,236)	(1,951)
Cash flows from financing activities:			
Proceeds from borrowings under credit arrangements	2,844	3,958	1,483
Repayments of borrowings under credit arrangements	(2,930)	(4,007)	(1,732)
Proceeds from issuance of senior notes	1,000	750	
Proceeds from issuance of senior subordinated notes			694
Debt issue costs	(10)	(16)	(8)
Repayment of senior notes			(175)
Repayment of senior subordinated notes	(875)		
Proceeds from issuances of common stock	2	13	34
Purchases of treasury stock, net	(7)	(14)	(14)
Net cash provided by financing activities	24	684	282
Increase (decrease) in cash and cash equivalents	12	37	(39)
Cash and cash equivalents, beginning of period	76	39	78
Cash and cash equivalents, end of period	$ 88	$ 76	$ 39

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 (NGLs). Our principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and onshore Gulf Coast. 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 natural 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, our or the Company are to Newfield Exploration Company and its subsidiaries.

Dependence on Commodity Prices

As an independent oil and natural gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for oil, natural gas and NGLs. Historically, the energy markets have been very volatile, and there can be no assurance that commodity prices will not be subject to wide fluctuations in the future. A substantial or extended decline in commodity 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, natural gas and NGL 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, natural gas and NGLs reserves. Actual results could differ significantly from these estimates. Our most significant financial estimates are associated with our estimated proved oil, natural gas and NGL 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 (loss), stockholders equity or cash flows.

Revenue Recognition

Substantially all of our oil, natural gas and NGLs are 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, natural gas and NGLs on properties in which we have joint ownership are recorded under the sales method. Under the sales method, the company and other joint owners may sell more or less than their entitled share of production. Should the company s excess sales exceed our share of estimated remaining reasonable reserves, a liability is recorded. Differences between these sales and our entitled share of production are not significant.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 operations.

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 2012, 2011 and 2010 of $3 million, $2 million and $1 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 natural gas operations and oil produced but not sold in our offshore operations in Malaysia and China. Inventories are carried at the lower of cost or market. At December 31, 2012, we wrote down subsea wellhead inventory that was not included in the sale of our Gulf of Mexico assets. The writedown of $8 million is included in Operating expenses Other on our consolidated statement of operations.

Substantially all of the crude oil from our offshore operations in Malaysia and China is produced into floating production, storage and off-loading vessels (FPSOs) or onshore storage terminals and lifted and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 744,000 barrels and 239,000 barrels of crude oil valued at cost of $64 million and $19 million at December 31, 2012 and 2011, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depletion expense.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $123 million, $113 million and $79 million of internal costs in 2012, 2011 and 2010, 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 using 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. 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, natural gas and NGL reserve estimation requirements, which require use of the unweighted average first-day-of-the-month commodity prices for the prior 12 months, adjusted for market differentials (SEC pricing), applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus

- the cost of properties not included in the costs being amortized, if any; less

- related income tax effects.

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, gas and NGL prices decrease significantly for a prolonged period of time or if we have substantial downward revisions in our estimated proved reserves. At December 31, 2012, the ceiling value of our reserves was calculated based upon SEC pricing of $2.76 per MMBtu for natural gas and $94.84 per barrel for oil. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties exceeded the ceiling amount by approximately $1.5 billion ($948 million, after-tax). The ceiling with respect to our properties in Malaysia and China exceeded the net capitalized costs of properties, requiring no writedown at December 31, 2012.

The continued decline of SEC pricing of oil and natural gas since December 31, 2012 may result in additional ceiling test writedowns in the first quarter of 2013 and possibly thereafter.

At December 31, 2011, the ceiling value of our reserves was calculated based upon SEC pricing of $4.12 per MMBtu for natural gas and $96.13 per barrel for oil. 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 SEC pricing of $4.38 per MMBtu for natural gas and $79.42 per barrel for oil. 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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

See Note 3, Oil and Gas Assets, for a detailed discussion regarding our acquisition and sales transactions during 2012, 2011 and 2010.

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 ARO is incurred. Settlements include payments made to satisfy the AROs, as well as transfer of the ARO to purchasers of our divested properties.

In general, the amount of an ARO and the costs capitalized will equal 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 original 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 operations.

The change in our ARO for each of the three years ended December 31, is set forth below:

	2012	2011	2010
		(In millions)	
Balance at January 1	$ 145	$ 108	$ 92
Accretion expense	11	10	8
Additions	24	33	21
Revisions	12	3	(8)
Settlements[1]	(50)	(9)	(5)
Balance at December 31	142	145	108
Less: Current portion of ARO at December 31	(10)	(10)	(11)
Total long-term ARO at December 31	$ 132	$ 135	$ 97

(1) For the year ended December 31, 2012, settlements include $28 million related to the sale of our Gulf of Mexico assets. See Note 3, Oil and Gas Assets.

Contingencies

We are subject to legal proceedings, claims, liabilities and environmental matters that arise in the ordinary course of business. We accrue for losses when such losses are considered probable and the amounts can be reasonably estimated. See Note 12, Commitments and Contingencies, for a more detailed discussion regarding our contingencies.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Environmental Matters

Environmental costs that relate to current operations are expensed as incurred. Remediation costs that relate to an existing condition caused by past operations are accrued when it is probable that those costs will be incurred and can be reasonably estimated based upon evaluations of currently available facts related to each site.

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, 2012, we did not have a liability for uncertain tax positions and as such we had not accrued related interest or penalties. The tax years 2009-2012 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 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 grant or modification date 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 stock units that are accounted for under the liability method which requires us 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, gas and NGL 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, gas and NGLs 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, 2012, seven of our 15 counterparties accounted for approximately 85% of our estimated future hedged production, with no single counterparty accounting for more than 25% of that production.

Major Customers

Royal Dutch Shell plc, Tesoro Corporation and Big West Oil LLC accounted for 14%, 14% and 10% respectively, of our consolidated revenues in 2012. During 2011, sales of our oil and gas production to Royal Dutch Shell plc and Tesoro Corporation accounted for 12% and 11%, respectively, of our consolidated revenues. No single customer accounted for 10% or more of our sales of oil and gas production during 2010. 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 consolidated 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 periodically utilize 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, 2012, accumulated other comprehensive loss consisted of a $6 million unrealized loss on investments and a $1 million unrealized loss on post-retirement benefits. 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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

New Accounting Requirements

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.

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 effective for interim and annual periods beginning on or after December 15, 2011. We adopted the provisions for the quarter ended March 31, 2012. Adopting the reporting 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 required, for Level 3 fair value measurements, disclosure of 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 adopted the provisions for the quarter ended March 31, 2012. Adopting the additional fair value measurement and disclosure requirements did not have a material impact on our financial position or results of operations.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 (excluding 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 the indicated years:

	2012	2011	2010
	(In millions, except per share data)		
Income (numerator):			
Net income (loss) basic and diluted	$ (1,184)	$ 539	$ 523
Weighted-average shares (denominator):			
Weighted-average shares basic	135	134	132
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	135	134
Earnings (loss) per share:			
Basic	$ (8.80)	$ 4.03	$ 3.97
Diluted	$ (8.80)	$ 3.99	$ 3.91

(1) 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, 2012 as their effect would have been anti-dilutive. Had we recognized net income for that year, 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 0.7 million shares for the year.

(2) The calculation of shares outstanding for diluted EPS for the years ended December 31, 2011 and 2010 excludes the effect of 1.4 million and 0.7 million, respectively, unvested restricted stock or restricted stock units and stock options because including the effect would be anti-dilutive.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at December 31:

	2012	2011	2010
		(In millions)	
Oil and gas properties:			
Subject to amortization	$ 12,655	$ 12,423	$ 10,627
Not subject to amortization	1,550	1,965	1,658
Gross oil and gas properties	14,205	14,388	12,285
Accumulated depreciation, depletion and amortization	(7,378)	(6,436)	(5,730)
Net oil and gas properties	6,827	7,952	6,555
Other property and equipment	141	138	114
Accumulated depreciation and amortization	(66)	(70)	(61)
Net other property and equipment	75	68	53
Total property and equipment, net	$ 6,902	$ 8,020	$ 6,608

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 in progress at December 31 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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following is a summary of our oil and gas properties not subject to amortization as of December 31, 2012. 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, 2012, approximately 85% of oil and gas properties not subject to amortization were associated with our unconventional resource plays.

	Costs Incurred In				
	2012	2011	2010	2009 and Prior	Total
			(In millions)		
Acquisition costs	$ 135	$ 249	$ 261	$ 234	$ 879
Exploration costs	260	24	22	28	334
Development costs	31	62	25	36	154
Fee mineral interests				23	23
Capitalized interest	68	78	14		160
Total oil and gas properties not subject to amortization	$ 494	$ 413	$ 322	$ 321	$ 1,550

Gulf of Mexico Asset Sale

On October 5, 2012, we closed on the sale of our remaining assets in the Gulf of Mexico to W&T Offshore, Inc. for approximately $208 million, subject to customary post-closing adjustments. The sale of our remaining assets in the Gulf of Mexico did not significantly alter the relationship between capitalized costs and proved reserves and as such, all proceeds were recorded as adjustments to our domestic full cost pool with no gain or loss recognized. These consolidated financial statements include the results of our Gulf of Mexico operations through the date of sale.

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 Unit.

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.

Other Asset Acquisitions and Sales

During 2012, 2011 and 2010, we acquired various other oil and gas properties for approximately $9 million, $1 million and $108 million, respectively, and sold various other non-strategic oil and gas properties for proceeds of approximately $630 million (includes Gulf of Mexico asset sale discussed above), $406 million and $12 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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Derivative Financial Instruments:

Commodity Derivative Instruments

We utilize fixed price swaps, purchased put options (floors), collars (combination of purchased put options and sold call options (ceiling)) and three-way collars (combination of a collar and the sale of additional put options with a strike price below the floor of the collar) 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 income 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 while we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price. 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, estimated volatility and, in the case of collars and floors, the remaining term 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 operations under the caption Commodity derivative income. Settlements of derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2012, we had outstanding contracts with respect to our future production that were not designated for hedge accounting as set forth in the tables below.

Natural Gas

			NYMEX Contract Price Per MMBtu						
					Collars				
			Additional Put		Floors		Ceilings		Estimated Fair Value
Period and Type of Contract	**Volume in MMMBtus**	**Swaps (Weighted Average)**	**Range**	**Weighted Average**	**Range**	**Weighted Average**	**Range**	**Weighted Average**	**Asset (Liability) (In millions)**
January 2013 March 2013									
Price swap contracts	13,500	$ 4.07							$ 10
Price swap contracts	(A)	3.46							1
3-Way collar contracts	10,800		$ 3.50-$4.50	$ 4.08	$ 5.00-$6.00	$ 5.58	$ 6.00-$7.55	$ 6.89	16
April 2013 June 2013									
Price swap contracts	13,650	4.07							8
Price swap contracts	(A)	3.46							
3-Way collar contracts	10,920		3.50-4.50	4.08	5.00-5.75	5.44	6.00-6.65	6.36	13
July 2013 September 2013									
Price swap contracts	13,800	4.07							6
Price swap contracts	(A)	3.46							(1)
3-Way collar contracts	11,040		3.50-4.50	4.08	5.00-5.75	5.44	6.00-6.65	6.36	12
October 2013 December 2013									
Price swap contracts	13,800	4.09							4
Price swap contracts	(A)	3.44							(2)
3-Way collar contracts	6,770		3.50-4.50	3.82	5.00-5.75	5.24	6.00-6.65	6.20	7
Collar contracts	4,575				3.75	3.75	4.54-4.60	4.57	1
January 2014 December 2014									
Price swap contracts	63,875	3.90							(8)
Collar contracts	23,725				3.75	3.75	4.54-4.75	4.62	2
January 2015 December 2015									
Price swap contracts	10,950	4.31							1
Collar contracts	10,950				3.75	3.75	5.02-5.08	5.06	
									$ 70

(A) During the first quarter of 2012, natural gas spot market prices were below the puts we sold on our three-way collars for April through December 2012 and the full-year 2013, exposing us further to the softening natural gas spot market. As a result, during the first quarter of 2012 we entered into additional fixed-price swap contracts in the over-the-counter market that effectively prevented any further erosion in the value of our natural gas three-way collars. The new swap contracts added during the first quarter of 2012 were for the same volumes as our full-year 2013 three-way collar contracts. The economics from the combination of these additional fixed-price swap contracts and our natural gas three-way collar contracts will result in effective average fixed prices of $4.96, $4.82. $4.82 and $4.86 per MMBtu for the first, second, third and fourth quarter of 2013, respectively, as long as natural gas spot prices for the respective time periods settle below the puts we sold on our three-way collar contracts. In the event natural gas spot prices settle above the ceilings on our associated three-way collar volumes, we would not recover the difference through the sale of our production as we would realize losses on both instruments discussed above.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Oil

Period and Type of Contract	Volume in MBbls	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 2013 March 2013									
Price swap contracts	270	$ 88.57							$ (1)
3-Way collar contracts	2,548		$ 80.00	$ 80.00	$ 95.00	$ 95.00	$ 106.50-130.40	$ 117.34	12
April 2013 June 2013									
Price swap contracts	364	88.63							(2)
3-Way collar contracts	2,912		80.00	80.00	95.00	95.00	106.50-130.40	117.88	12
July 2013 September 2013									
Price swap contracts	276	88.57							(1)
3-Way collar contracts	3,189		80.00	80.00	95.00	95.00	106.50-130.40	118.22	12
October 2013 December 2013									
3-Way collar contracts	3,466		80.00	80.00	95.00	95.00	106.50-130.40	118.54	12
January 2014 December 2014									
Price swap contracts	2,555	88.60							(9)
3-Way collar contracts	5,110		80.00	80.00	95.00	95.00	117.50-120.75	119.16	16
									$ 51

Interest Rate Swap

We previously hedged $50 million principal amount of our $175 million 7 $^5/_8$% 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 7 $^5/_8$% 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 consolidated balance sheet as assets (liabilities) at their respective estimated fair value, as set forth below at December 31:

	Gross Fair Value Asset	Gross Fair Value Liability	Balance Sheet Location Derivative Assets Current	Derivative Assets Noncurrent	Derivative Liabilities Current	Derivative Liabilities Noncurrent
	(In millions)					
December 31, 2012						
Natural gas contracts	$ 86	$ (16)	$ 79	$ 2	$ (4)	$ (7)
Oil contracts	77	(26)	46	15	(2)	(8)
Total	$ 163	$ (42)	$ 125	$ 17	$ (6)	$ (15)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Gross Fair Value		Balance Sheet Location: Derivative Assets		Balance Sheet Location: Derivative Liabilities	
	Asset	Liability	Current	Noncurrent	Current	Noncurrent
			(In millions)			
December 31, 2011						
Natural gas contracts	$ 194	$	$ 133	$ 61	$	$
Oil contracts	41	(88)	1		(45)	(3)
Basis contracts		(10)	(5)		(5)	
Total	$ 235	$ (98)	$ 129	$ 61	$ (50)	$ (3)

The amount of gain (loss) recognized in Commodity derivative income in our consolidated statement of operations related to our derivative financial instruments was as follows at December 31:

Type of Contract	2012	2011	2010
		(In millions)	
Derivatives not designated as hedging instruments:			
Realized gain on natural gas contracts	$ 144	$ 249	$ 290
Realized gain (loss) on oil contracts	1	(47)	141
Realized loss on basis contracts	(10)	(7)	(5)
Total realized gain	135	195	426
Unrealized gain (loss) on natural gas contracts	(124)	(48)	109
Unrealized gain (loss) on oil contracts	99	47	(222)
Unrealized gain on basis contracts	10	1	3
Total unrealized loss	(15)		(110)
Total	$ 120	$ 195	$ 316

The total realized gain on commodity derivatives for the year ended December 31, 2010 differs from the net cash receipts on derivative settlements due to the recognition of option premiums associated with derivatives settled during the respective period.

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, 2012, seven of our 15 counterparties accounted for approximately 85% of our estimated future hedged production, with no single counterparty accounting for more than 25% of that production.

A significant portion of our derivative instruments are with 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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Accounts Receivable:

Accounts receivable consisted of the following at December 31:

	2012	2011
	(In millions)	
Revenue	$ 291	$ 301
Joint interest	154	96
Other	8	11
Reserve for doubtful accounts	(1)	(1)
Total accounts receivable	$ 452	$ 407

6. Accrued Liabilities:

Accrued liabilities consisted of the following at December 31:

	2012	2011
	(In millions)	
Revenue payable	$ 95	$ 94
Accrued capital costs	355	231
Accrued lease operating expenses	95	86
Employee incentive expense	50	61
Accrued interest on debt	43	52
Taxes payable	108	122
Other	55	41
Total accrued liabilities	$ 801	$ 687

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 commodity options including, price collars, floors and three-way collars and other financial investments. Although we utilize third-party broker quotes to assess the reasonableness of our prices and valuation techniques for derivative instruments, 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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Fair Value of Investments and Derivative Instruments

The following table summarizes the valuation of our financial assets (liabilities) by measurement 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, 2011:				
Deferred compensation plan assets	$ 4	$	$	$ 4
Investments available-for-sale:				
Equity securities	6			6
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
As of December 31, 2012:				
Money market fund investments	$ 22	$	$	$ 22
Deferred compensation plan assets	6			6
Investments available-for-sale:				
Equity securities	7			7
Auction rate securities			36	36
Oil and gas derivative swap contracts		6		6
Oil and gas derivative option contracts			115	115
Total	$ 35	$ 6	$ 151	$ 192

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, 2012, we held $36 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 since the time of purchase of $9 million ($6 million net of tax) recorded under the caption Accumulated other comprehensive loss on our consolidated balance sheet. As of December 31, 2011, we held $32 million of auction rate securities, which reflected a decrease in the fair value of $13 million ($8 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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets 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, 2010	$ 40	$ 159	$ 199
Total realized or unrealized gains (losses):			
Included in earnings		31	31
Included in other comprehensive income (loss)	(2)		(2)
Purchases, issuances and settlements:			
Settlements	(8)	(142)	(150)
Transfers in and out of Level 3			
Balance at December 31, 2010	$ 30	$ 48	$ 78
Change in unrealized gains or losses 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 (loss)	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 or losses included in earnings relating to investments and derivatives still held at December 31, 2011	$	$ 56	$ 56
Balance at January 1, 2012	$ 32	$ 71	$ 103
Total realized or unrealized gains (losses):			
Included in earnings		135	135
Included in other comprehensive income (loss)	4		4
Purchases, issuances and settlements:			
Settlements		(91)	(91)
Transfers in and out of Level 3			
Balance at December 31, 2012	$ 36	$ 115	$ 151
Change in unrealized gains or losses included in earnings relating to investments and derivatives still held at December 31, 2012	$	$ 82	$ 82

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Commodity Derivatives. Our valuation models for derivative contracts are primarily industry-standard models that consider various factors, including certain significant unobservable inputs such as (a) quoted forward prices for commodities, (b) volatility factors and (c) counterparty credit risk. 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. Significant increases (decreases) in the quoted forward prices for commodities generally leads to corresponding decreases (increases) in the fair value measurement of our oil and gas derivative contracts. Significant changes in the volatility factors utilized in our option-pricing model can cause significant changes in the fair value measurement of our oil and gas derivative contracts.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The determination of the fair values of derivative instruments incorporates various factors that 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). Historically, we have not experienced significant changes in the fair value of our derivative contracts resulting from changes in counterparty credit risk as the counterparties for all of our hedging transactions have an investment grade credit rating.

Auction Rate Securities. We utilize a discounted cash flow model in the determination of the valuation of our auction rate securities classified as Level 3. This model considers various inputs including (a) the coupon rate specified under the debt instrument, (b) the current credit rating of the underlying issuers, (c) collateral characteristics and (d) risk-adjusted discount rates. The most significant unobservable factor in the determination of the investments fair value, however, is market liquidity for these instruments. A significant change in the liquidity of the market for auction rate securities would lead to a corresponding change in the fair value measurement of these investments.

Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Instrument Type	Estimated Fair Value Asset (Liability) (In millions)	Valuation Technique	Unobservable Input	Range	
		Quantitative Information about Level 3 Fair Value Measurements			
Oil option contracts	$ 64	Option model	NYMEX Oil price forward curve	$89.51	$93.76
			Oil price volatility curves	21.67%	33.94%
			Credit risk	0.01%	1.67%
Natural gas option contracts	$ 51	Option model	NYMEX Natural gas price forward curve	$3.35	$4.48
			Natural gas price volatility curves	21.92%	37.36%
			Credit risk	0.01%	3.10%

The underlying inputs in the determination of the valuation of our auction rate securities are developed by a third party and, therefore, not included in the quantitative analysis above.

Fair Value of Debt

The estimated fair value of our notes, based on quoted prices in active markets (Level 1) as of December 31, was as follows:

	2012	2011
	(In millions)	
5 3/4% Senior Notes due 2022	$ 836	$ 808
5 5/8% Senior Notes due 2024	1,074	
6 5/8% Senior Subordinated Notes due 2014		329
6 5/8% Senior Subordinated Notes due 2016		568
7 1/8% Senior Subordinated Notes due 2018	630	635
6 7/8% Senior Subordinated Notes due 2020	749	745

Any amounts outstanding under our credit arrangements at December 31, 2012 and 2011 are stated at cost, which approximates fair value. Please see Note 8, Debt.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Debt:

At December 31, our debt consisted of the following:

	2012	2011
	(In millions)	
Senior unsecured debt:		
Revolving credit facility LIBOR based loans	$	$ 85
Money market lines of credit(1)		1
Total credit arrangements		86
5 $^3/_4$% Senior Notes due 2022	750	750
5 $^5/_8$% Senior Notes due 2024	1,000	
Total senior unsecured debt	1,750	836
6 $^5/_8$% Senior Subordinated Notes due 2014		325
6 $^5/_8$% Senior Subordinated Notes due 2016		550
7 $^1/_8$% Senior Subordinated Notes due 2018	600	600
6 $^7/_8$% Senior Subordinated Notes due 2020	700	700
Discount on notes	(5)	(5)
Total long-term debt	$ 3,045	$ 3,006

(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, if any, are classified as long-term.

Credit Arrangements

We have a 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, 2012, 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, 2012) 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, 2012).

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, 2012). We incurred aggregate commitment fees under our current and previous credit facilities of approximately $3 million, $2 million and $2 million for each of the years ended December 31, 2012, 2011 and 2010, respectively, which are recorded in Interest expense on our consolidated statement of operations.

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, 2012, we were in compliance with all of our debt covenants.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2012, we had no letters of credit outstanding under our credit facility. 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, 2012). Additionally, as of December 31, 2012, we had $5 million of other undrawn letters of credit outstanding.

Subject to compliance with the restrictive covenants in our credit facility, at December 31, 2012, we also had a total of $145 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 issued $750 million of 5 $^{3}/_{4}$% 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 5 $^{3}/_{4}$%. We used the net proceeds to repay a portion of our then outstanding borrowings under our credit facility and money market lines of credit.

In June 2012, we issued $1 billion of 5 $^{5}/_{8}$% Senior Notes due 2024 and received proceeds of $990 million (net of offering costs). These notes were issued at par to yield 5 $^{5}/_{8}$%. We used a portion of the net proceeds to repay borrowings outstanding under our credit facility and money market lines of credit as well as redeem our 6 $^{5}/_{8}$% Senior Subordinated Notes due 2016 discussed below.

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 indentures governing our senior notes contain 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 indentures also provide 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. At December 31, 2012, we were in compliance with all of our debt covenants.

Senior Subordinated Notes

In April 2012, we redeemed our $325 million aggregate principal of 6 $^{5}/_{8}$% Senior Subordinated Notes due 2014 at 101.1042% of the principal amount plus accrued interest, which included the payment of an early

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

redemption premium of $4 million. This premium was recorded under the caption Other income (expenses) Other on our consolidated statement of operations. The repayment of the outstanding principal balance of $325 million was funded through the use of our revolving credit facility. In addition, unamortized offering costs of approximately $0.6 million were charged to interest expense.

In July 2012, we redeemed our $550 million aggregate principal amount of 6 $^{5}/_{8}$% Senior Subordinated Notes due 2016. In connection with the redemption, we paid a premium of $14 million. The premium was recorded under the caption Other income (expenses) Other on our consolidated statement of operations. In addition, unamortized offering costs of approximately $2 million were charged to interest expense as a result of the repayment.

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 7 $^{1}/_{8}$% Senior Subordinated 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 6 $^{7}/_{8}$% Senior Subordinated 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.

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.

At December 31, 2012, we were in compliance with all of our debt covenants.

9. Income Taxes:

For the years ended December 31, income (loss) before income taxes consisted of the following:

	2012	2011	2010
		(In millions)	
U.S.	$ (1,415)	$ 618	$ 658
Malaysia	387	185	150
Other International	40	37	21
Total income (loss) before income taxes	$ (988)	$ 840	$ 829

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the years ended December 31, the total provision for income taxes consisted of the following:

	2012	2011 (In millions)	2010
Current taxes:			
U.S. federal	$ 1	$ 17	$ (1)
U.S. state	1		
Malaysia	179	73	60
Other International	14	3	
Deferred taxes:			
U.S. federal	42	171	228
U.S. state	(34)	30	16
Malaysia	(5)		(4)
Other International	(2)	7	7
Total provision for income taxes	$ 196	$ 301	$ 306

The provision for income taxes for each of the indicated years was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	2012	2011 (In millions)	2010
Amount computed using the statutory rate	$ (346)	$ 294	$ 290
Increase (decrease) in taxes resulting from:			
State and local income taxes, net of federal effect	(18)	10	11
Net effect of different tax rates in non-U.S. jurisdictions	12	6	5
Valuation allowance	446	5	
Foreign tax credit	(421)		
Unremitted international earnings	521		
Other	2	(14)	
Total provision for income taxes	$ 196	$ 301	$ 306

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, the components of our deferred tax asset and deferred tax liability were as follows:

	U.S.	Malaysia	Other International	Total
		(In millions)		
December 31, 2012				
Deferred tax asset:				
Net operating loss carryforwards	$ 207	$	$ 6	$ 213
Alternative minimum tax credit	103			103
Stock-based compensation	24			24
Marketable securities	4			4
Oil and gas properties		49		49
Valuation allowance	(426)	(25)	(6)	(457)
Foreign tax credit	421			421
Other	18			18
Deferred tax asset	351	24		375
Deferred tax liability:				
Commodity derivatives	(44)			(44)
Oil and gas properties	(1,241)	(9)	(33)	(1,283)
Deferred tax liability	(1,285)	(9)	(33)	(1,327)
Net deferred tax liability	(934)	15	(33)	(952)
Less: Net current deferred tax liability	(42)			(42)
Net noncurrent deferred tax liability	$ (892)	$ 15	$ (33)	$ (910)

	U.S.	Malaysia	Other International	Total
		(In millions)		
December 31, 2011				
Deferred tax asset:				
Net operating loss carryforwards	$ 651	$ 11	6	$ 668
Alternative minimum tax credit	102			102
Stock-based compensation	22			22
Marketable securities	5			5
Oil and gas properties		28		28
Valuation allowance	(5)		(6)	(11)
Other	9			9
Deferred tax asset	784	39		823
Deferred tax liability:				
Commodity derivatives	(50)			(50)
Oil and gas properties	(1,660)	(29)	(35)	(1,724)

Deferred tax liability	(1,710)	(29)	(35)	(1,774)
Net deferred tax liability	(926)	10	(35)	(951)
Less: Net current deferred tax liability	(28)			(28)
Net noncurrent deferred tax liability	$ (898)	$ 10	$ (35)	$ (923)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We evaluate our cash flows and capital projects for domestic and international operations annually. Our foreign operations generated excess cash flow for the first time in 2012, and we estimate them to be cash flow neutral or generating excess cash flow in future years. In the fourth quarter 2012, we restructured our foreign operations as a result of deciding to invest excess international cash into our domestic operations for the next few years, and consequently, the permanent international reinvestment tax assertion is no longer applicable. As a result, we recorded $521 million of U.S. deferred taxes for our inception-to-December 31, 2012 foreign earnings, which had not been recorded previously and will record U.S. taxes on future international earnings annually.

As of December 31, 2012 and 2011, we had gross net operating loss (NOL) carryforwards of approximately $0.5 billion and $2.0 billion for federal income tax and $1.6 billion and $1.0 billion for state income tax purposes, respectively, which may be used in future years to offset taxable income. NOL carryforwards of $223 million are subject to annual limitations due to stock ownership changes. We currently estimate that we will not be able to utilize $126 million of our various gross state NOLs because we do not have sufficient estimated future taxable income in the appropriate jurisdictions. To the extent not utilized, the federal NOL carryforwards will begin to expire during the years 2019 through 2031.

As of December 31, 2012 and 2011, we had gross NOL carryforwards for international income tax purposes of approximately $17 million and $48 million, respectively. During the year ended December 31, 2012, we utilized international NOLs of $31 million, which were generated in 2011. In addition, as of December 31, 2012 and 2011, 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 deferred tax assets 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, gas and NGL 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 deferred tax assets.

The rollforward of our deferred tax asset valuation allowance is as follows at December 31:

	2012	2011 (In millions)	2010
Balance at the beginning of the year	$ (11)	$ (6)	$ (6)
Charged to provision for income taxes:			
Malaysia valuation allowance	(25)		
Foreign tax credit valuation allowance	(421)		
U.S. state net operating loss carryforwards		(5)	
Balance at the end of the year	$ (457)	$ (11)	$ (6)

In the fourth quarter of 2012, we recorded a $25 million valuation allowance for our deferred tax asset in Malaysia due to insufficient estimated future taxable income. Also in the fourth quarter of 2012, we recorded a valuation allowance related to insufficient estimated future domestic taxable income to fully utilize foreign tax credits of $421 million, in conjunction with our decision to repatriate international earnings. The foreign tax credit deferred tax asset is fully offset by a valuation allowance.

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.

10. Stock-Based Compensation:

All stock-based compensation equity awards to employees and non-employee directors are currently granted under the 2011 Omnibus Stock Plan (our 2011 Plan). 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. These awards 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. We primarily utilize treasury shares when restricted stock is issued or restricted stock units vest.

Shares available for grant under our 2011 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, 2012, we had approximately (1) 3.3 million additional shares available for issuance pursuant to our existing plan if all future awards under our 2011 Plan are stock options, or (2) 1.8 million additional shares available for issuance pursuant to our existing plan if all future awards under our 2011 Plan are restricted stock or restricted stock units. Thus far, the majority of the awards under our 2011 Plan have been granted as restricted stock unit awards.

Our stock-based compensation consisted of the following for the years ended December 31:

	2012	2011	2010
		(In millions)	
Total stock-based compensation	$ 47	$ 40	$ 33
Capitalized in oil and gas properties	(12)	(11)	(11)
Net stock-based compensation expense	$ 35	$ 29	$ 22

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 2012, 2011 or 2010 because we did not have sufficient taxable income to fully realize the deduction. At December 31, 2012, we had unrecognized net operating losses of $118 million related to stock-based compensation.

As of December 31, 2012, we had approximately $83 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 periods. The full amount is expected to be recognized within 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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The table below provides information about stock option activity for the following years:

	Number of Shares Underlying Options (In thousands)	Weighted-Average Exercise Price per Share	Weighted-Average Grant Date Fair Value per Share	Weighted-Average Remaining Contractual Life (In years)	Aggregate Intrinsic Value[(1)] (In millions)
Outstanding at December 31, 2009	2,941	$ 29.82		4.7	$ 56
Granted			$		
Exercised	(1,388)	24.34			46
Forfeited	(14)	48.45			
Outstanding at December 31, 2010	1,539	34.58		4.7	58
Granted					
Exercised	(446)	29.54			18
Forfeited	(34)	46.73			
Outstanding at December 31, 2011	1,059	36.31		4.0	7
Granted					
Exercised	(94)	19.52			1
Forfeited	(64)	36.19			
Outstanding at December 31, 2012	901	$ 38.06		3.3	$ 1
Exercisable at December 31, 2012	832	$ 37.21		3.1	$ 1

(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, 2012, the last reported sales price of our common stock on the New York Stock Exchange was $26.78 per share.

The table below summarizes information about stock options outstanding and exercisable at December 31, 2012:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Underlying Options (In thousands)	Weighted-Average Remaining Contractual Life (In years)	Weighted-Average Exercise Price per Share	Number of Shares Underlying Options (In thousands)	Weighted-Average Exercise Price per Share
$15.01 to $17.50	27	0.1	$ 16.65	27	$ 16.65
17.51 to 22.50	12	0.6	19.26	12	19.26
22.51 to 27.50	126	1.2	24.79	126	24.79
27.51 to 35.00	277	2.0	31.06	277	31.06

35.01 to 41.72	35	2.3	38.40	35	38.40
41.73 to 48.45	424	5.1	48.45	355	48.45
	901	3.3	$ 38.06	832	$ 37.21

Restricted Stock. At December 31, 2012, our employees held an aggregate of 2.4 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, 2012, our employees held 0.4 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).

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The table below provides information about restricted stock and restricted stock unit activity for the following years:

	Service-Based Shares	Performance/ Market-Based Shares	Total Shares	Weighted-Average Grant Date Fair Value per Share
	(In thousands, except per share data)			
Non-vested shares outstanding at January 1, 2010	2,424	782	3,206	$ 31.60
Granted	582	140	722	52.20
Forfeited	(169)	(85)	(254)	33.09
Vested	(659)	(521)	(1,180)	32.78
Non-vested shares outstanding at December 31, 2010	2,178	316	2,494	36.84
Granted	1,014	130	1,144	64.35
Forfeited	(233)		(233)	44.79
Vested	(836)	(89)	(925)	34.86
Non-vested shares outstanding at December 31, 2011	2,123	357	2,480	49.52
Granted	1,589	184	1,773	35.29
Forfeited	(364)	(14)	(378)	47.34
Vested	(977)	(89)	(1,066)	41.70
Non-vested shares outstanding at December 31, 2012	2,371	438	2,809	$ 43.31

The total fair value of restricted stock and restricted stock units that vested during the years ended December 31, 2012, 2011 and 2010 was $44 million, $32 million and $39 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. In February 2012, the first tranche of the 2011 grants vested, which required settlement of approximately 44,000 cash-settled restricted units for approximately $1.7 million. As of December 31, 2012, 77,564 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 2012, options to purchase approximately 165,722 shares of our common stock were issued under our employee stock purchase plan. The weighted-average fair value of each option was $9.86 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 0.10%, an expected life of six months and weighted-average volatility of 49.43%. At December 31, 2012, 703,033 shares of our common stock remained available for issuance under the current plan.

100

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2011, options to purchase 85,982 shares of our common stock at a weighted-average fair value of $16.95 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 0.14%, an expected life of six months and weighted-average volatility of 32.21%.

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%.

11. 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, 2012, both our accumulated benefit obligation and our accrued benefit costs were $12 million. Our net periodic benefit cost was approximately $2 million for each of the years ended December 31, 2012 and 2011 and approximately $1 million for the year ended December 31, 2010.

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

2013 2017	$ 3
2018 2022	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.

Total incentive compensation expense for the years ended December 31, 2012, 2011 and 2010 was $41 million, $39 million and $36 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, excluding those 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, 2012, 2011 and 2010 totaled $10 million, $8 million and $6 million, respectively.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Commitments and Contingencies:

We have various commitments for firm transportation, operating lease agreements for office space and other agreements. As of December 31, 2012, future minimum payments under these non-cancelable agreements are as follows:

	Firm Transportation	Operating Leases	Other	Total
		(In millions)		
Year Ending December 31,				
2013	$ 78	$ 18	$ 376	$ 472
2014	78	17	54	149
2015	75	16	10	101
2016	73	13	4	90
2017	72	12	3	87
Thereafter	147	40	1	188
Total minimum future payments	$ 523	$ 116	$ 448	$ 1,087

Firm transportation is comprised of various agreements with third parties for oil and gas gathering and transportation. Rent expense with respect to our lease commitments for office space for the years ended December 31, 2012, 2011 and 2010 was $19 million, $16 million and $11 million, respectively. Our other agreements primarily consist of platform construction and drilling rigs. Payments under these contracts are accounted for as capital additions to our oil and gas properties.

As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities, which are not included in the table above. 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, 2012, these work-related commitments totaled $132 million, all of which were attributable to our international businesses.

We have various oil and gas production volume delivery commitments that are related to our domestic operations. As of December 31, 2012, our delivery commitments through 2024 were as follows:

Year Ending December 31,	Natural Gas (MMMBtus)	Oil[(1)] (MBbls)
2013	6,570	5,323
2014		7,482
2015		14,783
2016		14,823
2017		13,870
Thereafter		66,458
Total delivery commitments	6,570	122,739

(1) Our oil delivery commitments include a particular commitment with a Salt Lake City, Utah refiner. This delivery commitment will begin upon the refiner completing the expansion of their facility, which is expected in late 2014 or early 2015. Our delivery commitment is to deliver approximately 20,000 barrels of oil per day over a 10-year period. This delivery commitment represents approximately 50% of our committed oil volumes for each of the years 2015 through 2019, increases to 77% in 2020, and is 100% of our commitment through 2024.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. However, in the event that we are unable to meet our crude oil volume delivery commitments, we would incur deficiency fees ranging from $2.55 to $6.50 per barrel.

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 (a) claims from royalty owners for disputed royalty payments, (b) commercial disputes, (c) personal injury claims and (d) 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.

During the fourth quarter 2012, we settled a lawsuit where the Company was the plaintiff and recorded a gain of $13 million in Other income (expenses) Other on our consolidated statement of operations.

13. 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, 2012, 2011 and 2010. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

	Domestic	Malaysia	China (In millions)	Other International	Total
Year Ended December 31, 2012:					
Oil, gas and NGL revenues	$ 1,476	$ 1,005	$ 86	$	$ 2,567
Operating expenses:					
Lease operating	406	101	7		514
Production and other taxes	67	259	18		344
Depreciation, depletion and amortization	683	251	21		955
General and administrative	211	7			218
Ceiling test impairment	1,488				1,488
Other	15				15
Allocated income tax (benefit)	(516)	148	10		
Net income (loss) from oil and gas properties	$ (878)	$ 239	$ 30	$	
Total operating expenses					3,534
Loss from operations					(967)
Interest expense, net of interest income, capitalized interest and other					(141)
Commodity derivative income					120
Loss before income taxes					$ (988)

Total assets	$ 6,699	$ 866	$ 347	$	$ 7,912
Additions to long-lived assets	$ 1,655	$ 173	$ 87	$	$ 1,915

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Domestic	Malaysia	China (In millions)	Other International	Total
Year Ended December 31, 2011:					
Oil, gas and NGL 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 (In millions)	Other International	Total
Year Ended December 31, 2010:					
Oil, gas and NGL 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
Other	7				7
Allocated income tax (benefit)	165	59	6	(1)	
Net income (loss) from oil and gas properties	$ 282	$ 96	$ 19	$ (2)	
Total operating expenses					1,259
Income from operations					624
Interest expense, net of interest income, capitalized interest and other					(111)
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

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. Supplemental Cash Flows Information:

The following table presents information about supplemental cash flows for each of the years in the three-year period ended December 31:

	2012	2011 (In millions)	2010
Cash Payments:			
Interest payments, net of interest capitalized of $68, $82 and $58 during 2012, 2011 and 2010, respectively	$ 137	$ 79	$ 79
Income tax payments	206	70	87
Non-cash items excluded from the statement of cash flows:			
(Increase) decrease in accrued capital expenditures	$ (124)	$ 90	$ (8)
Increase in asset retirement costs	(8)	(33)	(13)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Related Party Transaction:

Kevin M. Robinson, our Vice President Asia, and Susan G. Riggs, our Treasurer, are minority owners of Huffco International L.L.C. (Huffco). In May 1997, before Mr. Robinson and 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 2012, 2011 and 2010, Newfield China paid $7 million, $5 million and $4 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 Mr. Robinson and Ms. Riggs had a net present value of approximately $94,000 and $235,000, respectively at December 31, 2012.

16. Quarterly Results of Operations (Unaudited):

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

	2012 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil, gas and NGL revenues	$ 678	$ 628	$ 615	$ 646
Income (loss) from operations(2)	197	111	106	(1,381)
Net income (loss)	116	135	(33)	(1,402)
Basic earnings (loss) per common share(1)	$ 0.86	$ 1.00	$ (0.24)	$ (10.39)
Diluted earnings (loss) per common share(1)	$ 0.86	$ 1.00	$ (0.24)	$ (10.39)

	2011 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil, gas and NGL 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(1)	$ (0.13)	$ 1.62	$ 1.99	$ 0.51

(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.

(2) Income (loss) from operations for the fourth quarter of 2012 includes a full cost ceiling test writedown of $1.5 billion.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED

Results of Operations for Oil and Gas Producing Activities

The following tables present the results of our oil and gas producing activities for the following years:

	Domestic	Malaysia	China	Total
		(In millions)		
Year Ended December 31, 2012				
Revenues	$ 1,469	$ 1,005	$ 86	$ 2,560
Production costs	292	101	7	400
Production taxes and other operating expenses	174	259	18	451
Depreciation, depletion and amortization	661	246	20	927
Impairment of oil and gas properties	1,488			1,488
Income taxes	(401)	152	10	(239)
Results of operations for oil and gas producing activities	$ (745)	$ 247	$ 31	$ (467)
Year Ended December 31, 2011				
Revenues	$ 1,735	$ 647	$ 82	$ 2,464
Production costs	258	90	5	353
Production taxes and other operating expenses	161	242	20	423
Depreciation, depletion and amortization	596	124	18	738
Income taxes	252	73	10	335
Results of operations for oil and gas producing activities	$ 468	$ 118	$ 29	$ 615
Year Ended December 31, 2010				
Revenues	$ 1,420	$ 399	$ 57	$ 1,876
Production costs	187	57	6	250
Production taxes and other operating expenses	116	72	9	197
Depreciation, depletion and amortization	501	108	16	625
Income taxes	216	62	7	285
Results of operations for oil and gas producing activities	$ 400	$ 100	$ 19	$ 519

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

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, 2012 are as follows:

	Domestic	Malaysia	China	Total
		(In millions)		
2012:				
Property acquisitions:				
Unproved	$ 64	$	$	$ 64
Proved	3			3
Exploration[1]	929	63	1	993
Development[2]	659	108	86	853
Total costs incurred[3]	$ 1,655	$ 171	$ 87	$ 1,913
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

(1) Includes $239 million, $237 million and $248 million of domestic costs for non-exploitation activities for 2012, 2011 and 2010, respectively; $63 million, $9 million and $27 million of Malaysia costs for non-exploitation activities for 2012, 2011 and 2010, respectively; and $1 million, $25 million and $24 million of China costs for non-exploitation activities for 2012, 2011 and 2010, respectively.

(2) Includes $9 million, $33 million and $13 million for 2012, 2011 and 2010, 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:

	2012	2011	2010
		(In millions)	
Property sales Domestic	$ 606	$ 434	$ 12
Ceiling test writedown Domestic	1,488		
	$ 2,094	$ 434	$ 12

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

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, 2012:

	Domestic	Malaysia	China	Total
		(In millions)		
December 31, 2012:				
Proved properties	$ 11,294	$ 1,140	$ 375	$ 12,809
Unproved properties	1,291	104	1	1,396
	12,585	1,244	376	14,205
Accumulated depreciation, depletion and amortization	(6,535)	(747)	(96)	(7,378)
Net capitalized costs	$ 6,050	$ 497	$ 280	$ 6,827
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

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.

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 our 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.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

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

	Year Ended December 31,		
	2012	2011 (Bcfe)	2010
Proved Reserves:			
Beginning of year	3,911	3,712	3,616
Reserve additions	516	909	676
Reserve revisions	(546)	(288)	(289)
Sales	(180)	(122)	(3)
Production	(303)	(300)	(288)
End of year	3,398	3,911	3,712

Our proved natural gas reserves at year-end 2012 were 1.8 Tcf compared to 2.3 Tcf and 2.5 Tcf at year-end 2011 and 2010, respectively. Our proved crude oil and condensate reserves at year-end 2012 were 237 MMBbls compared to 247 MMBbls and 198 MMBbls at year-end 2011 and 2010, respectively. Our proved NGL reserves at year-end 2012 were 37 MMBbls compared to 16 MMBbls and 6 MMBbls at year-end 2011 and 2010, respectively. Oil, condensate and NGLs comprised about 48%, 40% and 33% of our proved reserves at year-end 2012, 2011 and 2010, respectively.

Reserve Additions and Revisions. During 2012, our proved reserves decreased 30 Bcfe as a result of additions (extensions, discoveries, improved recovery and purchases of reserves in place) being more than offset by revisions of previous estimates, mostly due to price as described below. We expect the majority of future reserve growth 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 512 Bcfe of proved reserves through discoveries, extensions and other additions, and 4 Bcfe through purchases. Drilling additions related to our resource plays in the Mid-Continent, Rocky Mountains and South Texas constituted 92% of our additions. Of the drilling additions, 362 Bcfe or 60 MMBOE were proved undeveloped additions and 13 MMBOE were proved developed oil and NGL reserves.

We added 909 Bcfe of proved reserves during 2011. Approximately 857 Bcfe of the additions resulted from discoveries, extensions and other additions, and 52 Bcfe related to 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 MMBOE were proved undeveloped additions in the Rocky Mountains, associated primarily with the Williston basin and the Greater Monument Butte Unit. In addition, 16 MMBbls of proved developed oil reserves were added during 2011.

Revisions. While total proved reserve revisions in 2012 were a negative 546 Bcfe or 14% of the beginning of year proved reserves, they included a negative price revision of 616 Bcfe primarily related to our onshore natural gas plays. The largest area affected by lower natural gas prices was the Woodford Shale. Price revisions there were primarily to proved undeveloped reserves. In mature plays, dominated by infill drilling and where reserve growth cannot be classified as an extension or discovery, the change in reserves is captured as a revision. In 2012, our revisions associated with the development of existing fields were a positive 70 Bcfe.

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 in 2011 as we directed capital to

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

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 Green River section northwest of the Greater Monument Butte Unit encountered higher than expected natural gas production, (ii) the timing of waterflood response recognition in the Greater Monument Butte Unit, (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 region, which were adversely impacted by new horizontal well completions.

Sales. In 2012, we sold 180 Bcfe of proved reserves associated with non-strategic assets. In 2011, we sold 122 Bcfe of proved reserves associated with non-strategic assets. In 2010, sales of reserves were negligible.

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 and undeveloped reserves as of December 31, 2009, 2010, 2011 and 2012 and the changes in our total net proved reserves during the three-year period ended December 31, 2012:

	Crude Oil and Condensate (MMBbls)				Natural Gas (Bcf)			
	Domestic	Malaysia[1]	China[1]	Total	Domestic	Malaysia[1]	China[1]	Total
Proved developed and undeveloped reserves as of:								
December 31, 2009	134	25	7	166	2,605			2,605
Revisions of previous estimates	(9)	1		(8)	(268)			(268)
Extensions, discoveries and other additions	46	7		53	338			338
Purchases of properties	2			2	9			9
Sales of properties								
Production	(9)	(5)	(1)	(15)	(192)			(192)
December 31, 2010	164	28	6	198	2,492			2,492
Revisions of previous estimates	(24)	(2)		(26)	(175)			(175)
Extensions, discoveries and other additions	73	3	15	91	276	4		280
Purchases of properties	7			7	9			9
Sales of properties	(5)			(5)	(91)			(91)
Production	(11)	(6)	(1)	(18)	(182)			(182)
December 31, 2011	204	23	20	247	2,329	4		2,333
Revisions of previous estimates	(13)	2		(11)	(525)	(2)		(527)
Extensions, discoveries and other additions	38			38	181			181
Purchases of properties					1			1
Sales of properties	(15)			(15)	(80)			(80)
Production	(11)	(10)	(1)	(22)	(151)	(2)		(153)
December 31, 2012	203	15	19	237	1,755			1,755
Proved developed reserves as of:								
December 31, 2009	69	10	5	84	1,397			1,397
December 31, 2010	87	15	5	107	1,505			1,505
December 31, 2011	88	17	5	110	1,405	4		1,409
December 31, 2012	92	14	4	110	1,042			1,042
Proved undeveloped reserves as of:								
December 31, 2009	65	15	2	82	1,208			1,208
December 31, 2010	77	13	1	91	987			987
December 31, 2011	116	6	15	137	924			924
December 31, 2012	111	1	15	127	713			713

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

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Estimated Net Quantities of Proved Oil and Gas Reserves (Continued)

	NGLs (MMBbls)				Total Natural Gas Equivalents (Bcfe)			
	Domestic	Malaysia(1)	China(1)	Total	Domestic	Malaysia(1)	China(1)	Total
Proved developed and undeveloped reserves as of:								
December 31, 2009	3			3	3,424	151	41	3,616
Revisions of previous estimates	4			4	(298)	9		(289)
Extensions, discoveries and other additions					614	40		654
Purchases of properties					22			22
Sales of properties								