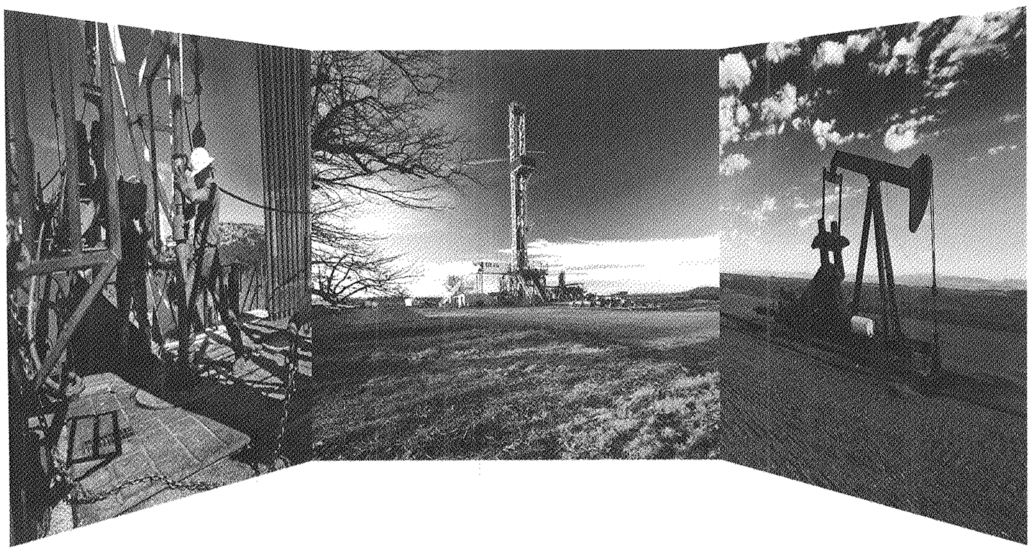
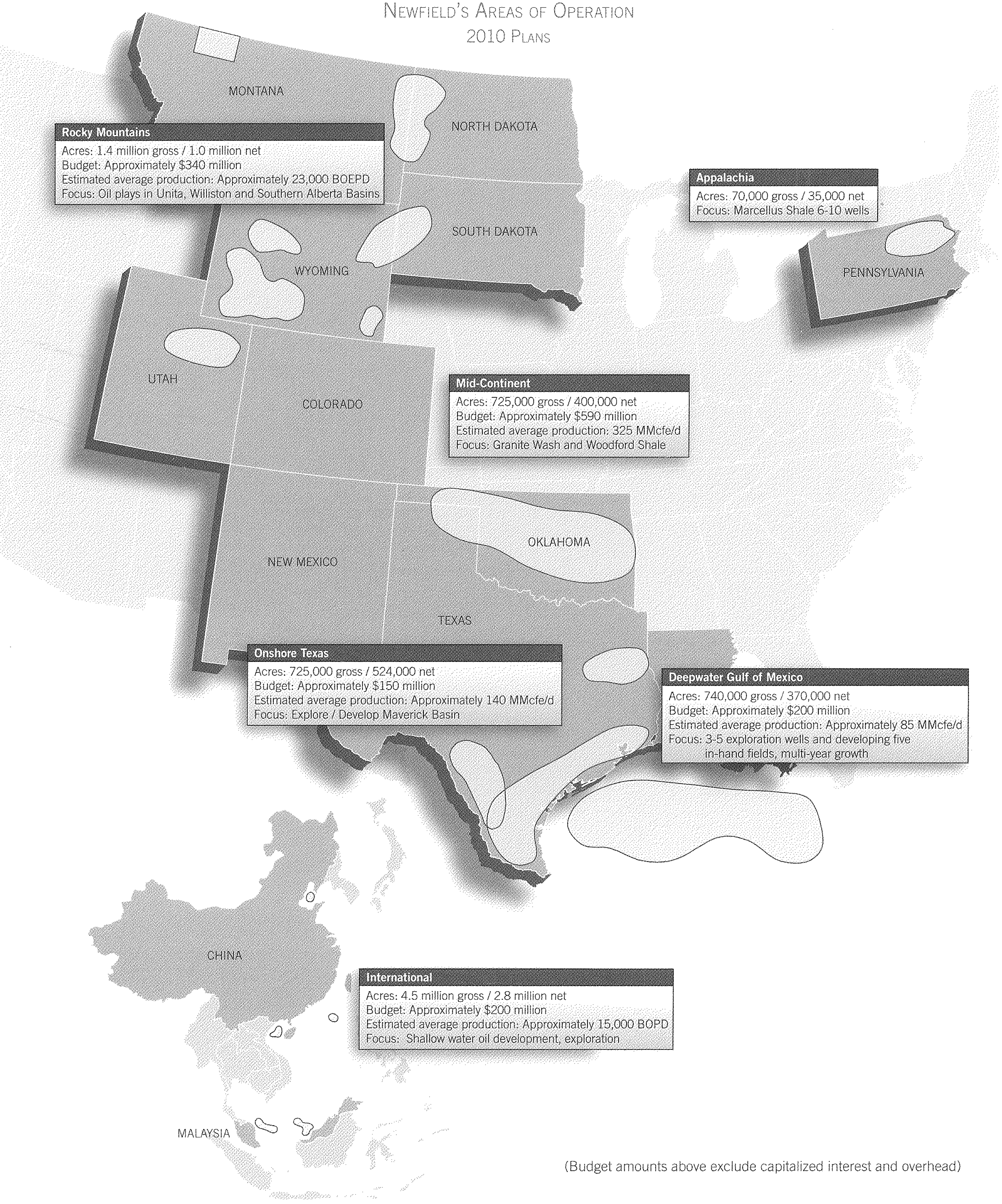
Right People. Right Projects. Right Time.



2009 Newfield Annual Report

NEWFIELD

Newfield's Areas of Operation
2010 Plans



(Budget amounts above exclude capitalized interest and overhead)

Dear Fellow Stockholders:

Thank you for your investment in Newfield Exploration Company.

2009 will be a year long-remembered. It opened with unprecedented turmoil in the world's financial markets. Although the outlook for crude oil and natural gas demand was weak, Newfield was well positioned with a strong capital structure, ample liquidity and a commodity hedge position that provided our stockholders with financial certainty. The year ended with a stronger and healthier Newfield. We enter 2010 with a diversified portfolio positioned for future growth.

Lee K. Boothby
President and CEO

Throughout our 21-year history, we have maintained a healthy balance sheet and this tradition has served us well.

For the year 2009, we had a net loss of $542 million, or $4.18 per diluted share. The loss relates primarily to low natural gas prices in early 2009 and a resulting ceiling test writedown of $854 million (after-tax). Excluding this charge, $387 million (after-tax) in unrealized commodity derivative losses (mark-to-market) and a $24 million international tax benefit, our net income for the year would have been $676 million, or $5.13 per share.

From the Newfield perspective, 2009 was an excellent year. We took full advantage of the many options afforded us from our diversified portfolio of assets. The year's highlights included:

Improved Capital Allocation—The economic conditions in the marketplace required us to make proactive business decisions. We repositioned our capital budget several times in 2009 as we shifted both human and capital resources to the projects that we felt would provide the best growth and return options. Our portfolio contains both oil and gas opportunities, providing us with an added element of flexibility. By better targeting our investments, we delivered improved returns.

Healthy Growth in Production and Reserves—Our production increased 9% in 2009 to 257 Bcfe. We delivered results in the upper half of our original guidance (250-260 Bcfe), despite a voluntary curtailment of about 3 Bcfe in the second half of 2009 due to low natural gas prices.

Our proved reserves at year-end 2009 were 3.6 Tcfe, a 23% increase over year-end 2008 reserves. Our improved allocation of capital and reductions in service costs resulted in lower cost reserve additions. We invested approximately $1.4 billion in 2009 and our finding and development (F&D) costs, including price and performance revisions, averaged approximately $1.50 per Mcfe. Excluding the negative impact of price related reserve revisions, our F&D costs would have been approximately $1.18 per Mcfe. Approximately half of our increase in proved reserves was related to changes in the Securities and Exchange Commission reserve reporting rules, which allowed us to record significant proved undeveloped reserves in our growing resource plays. Although natural gas prices were low during 2009, we increased our proved developed reserves by four percent during the year.

Delivered on our Growth Targets, Within Cash Flow, While Reducing Debt—We made a pledge early in the year that we would live within our cash flow from operations. We not only met our growth projections, but we had ample funds remaining to add new projects throughout the year and to reduce our debt by approximately $200 million. Lower service costs and the deferral of projects into future periods also allowed us to spend less during the year.

Lowered our Cash Costs in our Core Areas—In every division, reducing costs was a paramount goal in 2009. We coupled reduced service costs with continued gains in operational efficiency.

Attainment of our goals and the efforts we made to improve our capital allocation were recognized by Wall Street. Our stock was one of the top performers in our industry during 2009, up 144% from our low at the beginning of the year.

Our sights are set on 2010 and our goals are once again clearly defined:

1. We expect our 2010 production to grow 8-12% over 2009 levels and expect to have healthy growth in our proved reserve base.

2. We will remain focused on large, domestic resource plays of scale. Over the last six months, we added more than 500,000 net acres in resource plays. These will be our "plays of the future."

   Our largest transaction was the acquisition of a significant portion of TXCO Resources Inc.'s assets in the Maverick Basin for $215 million. This provided more than 300,000 net acres in the emerging Eagle Ford and Pearsall Shales in southwest Texas.

   We established a presence in the Appalachian region through our entry into the Marcellus Shale in northeastern Pennsylvania. Through a joint exploration agreement that we operate, we have interests in approximately 35,000 net acres, and we continue to lease in the area. We expect to begin assessment drilling in mid-2010.

   We also expanded our presence in oil plays through a new agreement with the Blackfeet Nation in northwestern Montana. We now have about 221,000 net acres in a geologically-similar play to the Williston Basin. In addition, we extended our Monument Butte area footprint, which now covers 180,000 net acres in the Uinta Basin, and includes our 63,000 net acre position on Ute Tribal acreage.

We are confident in our ability to invest in these types of plays and to deliver sustainable, repeatable growth at attractive returns.

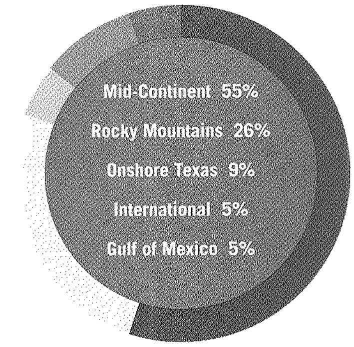
3. We will continue to increase our investments in oil plays. At year-end 2009, approximately 30% of our proved reserves, stated on a Mcf-equivalent basis (6:1), were oil. With today's significant disparity in oil and gas prices, a substantial portion of our 2010 revenues are expected to come from oil. In fact, on a 12:1 basis, about 45% of our total proved reserves at year-end 2009 would be oil. We expect that approximately 35% of our 2010 budget will be directed to oil projects. This is an advantage that we have over many of our "gassy" peer companies.

   We have long-lived oil plays in the Rocky Mountains and, with continued improvements in U.S. oil markets, we are confident that these areas are capable of higher growth rates. We are targeting 15% production growth at Monument Butte and 40% from our Williston Basin assets. Internationally, our offshore oil properties in Malaysia and China are generating high returns with an inventory of attractive development drilling opportunities.

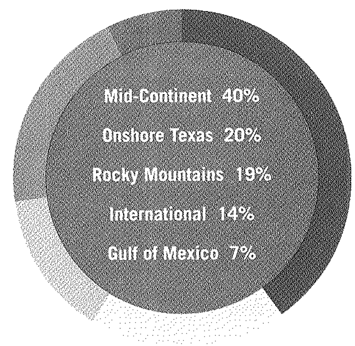
4. We have core competencies in marine environments and our assets in Southeast Asia and the deepwater Gulf of Mexico provide attractive investment options. Our long and successful history in the Gulf of Mexico has been used as the foundation for our entries into deepwater and International areas. Our Gulf of Mexico and International areas represent approximately 25% of our total planned 2010 investments and their potential impact is significant. We are finding attractive investment opportunities to add reserves and production.

5. We will continue to harvest assets, as appropriate, and re-invest cash flow into higher return areas. In 2007, we monetized $1.8 billion in assets, which included the sale of our shallow Gulf of Mexico and North Sea properties. In 2009, we elected to invest less in our conventional onshore Texas assets, therefore, harvesting cash flow from these assets and accelerating growth in our Rocky Mountain and Mid-Continent areas. A substantial portion of our onshore Texas investments in 2010 will be directed toward our new properties acquired from TXCO Resources.

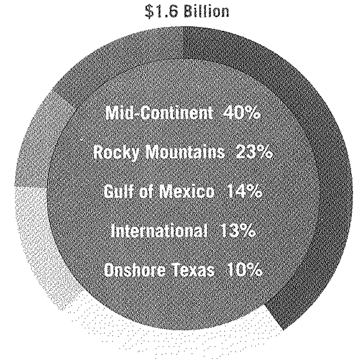
2009 Proved Reserves by Area
3.6 Tcfe



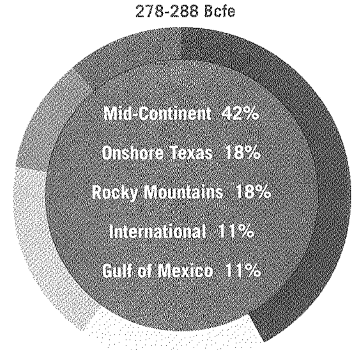
2009 Production By Area
257 Bcfe



2010 Budgeted Capital Expenditures
$1.6 Billion



Estimated 2010 Production
278-288 Bcfe



6. As always, we are committed to a strong balance sheet. Our longevity as a Company is directly related to sound business decisions and a capital structure that provides stability in periods of low commodity prices. In early 2010, we issued $700 million in 6⅞% Senior Subordinated Notes, using the proceeds to retire a significant portion of our $175 million of notes due in 2011, finance our recent acquisition of assets from TXCO Resources and repay outstanding borrowings under our credit arrangements.

HIGHLIGHTS FROM OUR CORE OPERATING AREAS ARE BELOW:

Unconventional Growth Areas

The Mid-Continent has been our fastest growing focus area. It represented 55% of our total proved reserves at year-end 2009. The region is expected to contribute more than 40% of our 2010 production.

Our two major growth drivers in the Mid-Continent are the Woodford Shale and the Granite Wash. Our Woodford production is now about 200 MMcfe/d net and is expected to grow more than 25% in 2010. Our operating personnel have made great strides in lowering development costs and improving our margins.

One of the primary drivers behind our improved results is the drilling of longer lateral wells. In 2009, the average lateral length of our Woodford completions was about 5,000', or double our average lateral length completion in 2006. We estimate that our average 2010 lateral completion will be about 6,000'.

In the Granite Wash, our production in 2009 grew to record levels as a result of our first horizontal completions in this mature play. We have effectively applied our experience from the Woodford to this area and have seen phenomenal results. Our largest field is Stiles/Britt Ranch. Since late 2008, we have drilled and completed 13 horizontal wells in the Granite Wash, with an average initial production rate of approximately 20 MMcfe/d gross. We have interests in more than 44,000 net acres in the Granite Wash.

In the Rocky Mountains, our primary investment regions are the proven Uinta and Williston Basins. We also will focus on the potential of the Southern Alberta Basin. Our properties here are substantially all oil assets. At year-end 2009, our Rocky Mountains region represented 26% of our total proved reserves and it is expected to comprise 18% of our 2010 production.

Our centerpiece oil asset in the Rocky Mountains is Monument Butte, where we expect to drill approximately 275 wells in 2010. We have an inventory of thousands of low risk development locations. Area production in mid-February 2010 was more than 17,000 BOPD gross and is expected to grow by 15% in 2010. We have taken advantage of improving demand and price differentials for our Black Wax crude and have increased our 2010 planned operated rig count to five.

We have an interest in about 150,000 prospective net acres in the Williston Basin. In addition, we own an interest in approximately 54,000 net acres in the mature Elm Coulee field. At year-end 2009, we had drilled 14 successful wells in the Bakken and Sanish/Three Forks formations. Our year-end 2009 production of 2,500 BOEPD net is expected to grow approximately 40% in 2010. We plan to run three rigs in this area in 2010.

Conventional Assets

In addition to our focus on unconventional resource plays of scale in the U.S., we also have a portfolio of conventional plays onshore Texas, in the deepwater Gulf of Mexico and offshore Malaysia and China.

In the deepwater Gulf of Mexico, we have drilled six successful operated wells out of seven attempts since 2005. We have five active developments underway that are expected to provide significant growth. We also have an inventory of prospects and anticipate drilling 3-5 deepwater wells per year over the next several years.

Our largest deepwater Gulf of Mexico discovery to date came in 2009 on our Pyrenees prospect. We continue to evaluate an 11-block area around Pyrenees where additional targets exist.

Onshore Texas, we slowed our activities in conventional gas plays during the year in response to lower natural gas prices. Due to this lack of investment and natural declines, we expect that production from our existing conventional fields onshore Texas will decline about 15% during 2010. However, our newly acquired assets in the Maverick Basin should allow our 2010 production from the region to remain relatively flat.

Newfield Enters the Maverick Basin

On February 11, 2010, we acquired assets from TXCO Resources Inc. in the Maverick Basin of southwest Texas for $215 million.

The acquisition included approximately 300,000 net acres and total net production of approximately 1,500 BOEPD. This marks our entry into the Maverick Basin and will allow us to apply our core competencies in horizontal drilling and completions to an unconventional new hydrocarbon-rich basin.

The Maverick Basin, which borders the Rio Grande River, has historically been underexplored. Adjacent to the well-known and heavily explored Gulf Coast Basin, the Maverick is characterized by a diverse stratigraphy. Multiple reservoirs have both oil and gas potential. Many believe the basin is one of the few areas in the mature, heavily developed region where operators can engage in new exploration.

We have multi-play potential on our acreage with a variety of opportunities ranging from dry gas formations… to wet gas… to oil. The prospective targets have drill depths ranging from 5,000’ – 10,000’ in the Eagle Ford Shale, Georgetown and Glen Rose formations and the Pearsall Shale. All of these are known oil and gas producers with recent industry successes in neighboring counties.

Our 2010 plans are to invest $100 million. Upon closing, we immediately went to work on our new acreage and expect to be running at least three operated rigs here by the summer. We plan to drill at least 12 wells in the Eagle Ford. We will apply our experiences in horizontal drilling and completions from the Woodford and Granite Wash, which should accelerate our learning curve.

Our 300,000 net acres include 167,000 net acres prospective for the Pearsall. By mid-summer, we will kick off an assessment drilling program in the Pearsall. Recent industry wells have been encouraging with lateral lengths pushing 5,000’ or more. We expect to drill 2-4 wells in the Pearsall in 2010.

All of our international assets are oil. With the strength in oil prices in 2009, our average daily production of nearly 17,000 BOPD net contributed 27% of our total revenues. We made an oil discovery in the South China Sea in 2009 on our Pearl prospect and we have additional exploration drilling planned in 2010. The Pearl field is under development with first production expected in late 2012.

2010 Outlook

Our planned 2010 investments align with our vision. We will focus and invest approximately 70% of our capital budget in domestic resource plays of scale. We are confident in the ability of these plays to deliver double-digit, sustainable production and reserve growth at attractive returns.

Our 2010 capital budget is aligned with our anticipated 2010 cash flow and is set at $1.6 billion. This level of investment should allow our production to grow 8-12% over 2009 levels.

We are in the second year of our third decade as a company and our future is bright. We will continue to be good stewards of capital and will invest in the right projects at the right time.

While we retain the entrepreneurial spirit of our founding, our diverse portfolio of assets today is providing optionality and flexibility in our investments. We have evolved into a larger, stronger and more diversified independent exploration and production company.

Our leadership is experienced and works with talented professionals throughout our operating regions. We enthusiastically share a confidence in our ability to execute on our plans in 2010.

Thank you for your continued interest and investment in our Company.

Lee K. Boothby
President and CEO

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2009

or

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

For the transition period from to

Commission file number: 1-12534

Newfield Exploration Company

(Exact name of registrant as specified in its charter)

Delaware *(State of incorporation)*	**72-1133047** *(I.R.S. Employer Identification No.)*
363 North Sam Houston Parkway East, Suite 100, Houston, Texas *(Address of principal executive offices)*	**77060** *(Zip Code)*

Registrant's telephone number, including area code: 281-847-6000

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

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

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

None

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

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $4.3 billion as of June 30, 2009 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 22, 2010, there were 133,063,941 shares of the registrant's common stock, par value $0.01 per share, outstanding.

Documents incorporated by reference: Proxy Statement of Newfield Exploration Company for the Annual Meeting of Stockholders to be held May 7, 2010, 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" or "our" are to Newfield Exploration Company and its subsidiaries. Unless otherwise noted, all information in this report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates we prepared and are net to our interest.

Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results, such as planned capital expenditures, future drilling plans and programs, expected production rates, the availability and sources of capital resources to fund capital expenditures, estimates of proved and probable reserves and the estimated present value of proved reserves, our financing plans and our business strategy and other plans and objectives for future operations. Although we believe that these expectations are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties and risks. Actual results may vary significantly from those anticipated due to many factors, including:

- oil and gas prices;
- general economic, financial, industry or business conditions;
- the impact of governmental regulations;
- the availability and cost of capital to fund our operations and business strategies;
- the ability and willingness of current or potential lenders, hedging contract counterparties, customers, and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us;
- the availability of refining capacity for the crude oil we produce from our Monument Butte field;
- drilling results;
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- labor conditions;
- weather conditions, and changes in weather patterns, including adverse conditions and changes in patterns due to climate change;
- the effect of worldwide energy conservation measures;
- the price and availability of, and demand for, competing energy sources; and
- the other factors affecting our business described below under the caption "Risk Factors."

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

PART I

Items 1 and 2. *Business and Properties*

We are an independent oil and gas company engaged in the exploration, development and acquisition of oil and gas properties. Our domestic areas of operation include the Anadarko and Arkoma Basins of the Mid-Continent, the Rocky Mountains, onshore Texas and the Gulf of Mexico. Internationally, we are also active in Malaysia and China.

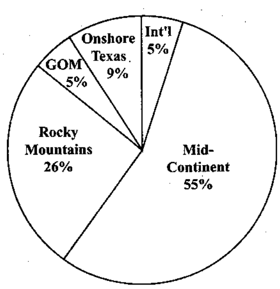
General information about us can be found at *www.newfield.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the Securities and Exchange Commission. Information contained on our website is not incorporated by reference into this report and you should not consider information contained on our website as part of this report.

Overview

We are a Delaware corporation and were founded in 1989. Our company began as a Gulf of Mexico focused company. Over the last decade, we have diversified our asset base and added multiple areas capable of sustainable growth. Our asset base and related capital programs are diversified both geographically and by type — offshore and onshore, domestic and international, conventional plays and unconventional "resource" plays in both oil and gas basins. Approximately 80% of our proved reserves and 85% of our probable reserves at year-end 2009 were located in resource plays, primarily in the Mid-Continent and the Rocky Mountains. Approximately 60% of our 2009 capital investments were allocated to growth opportunities in these regions. We expect our 2010 investment levels in these areas to be similar.

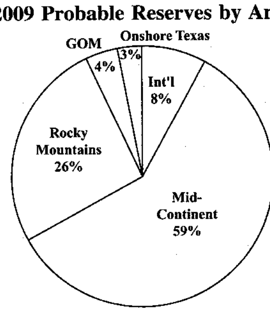
At year-end 2009, we had proved reserves of 3.6 Tcfe, a 23% increase over proved reserves at year-end 2008. At the end of 2009, our proved reserves were 72% natural gas and 53% proved developed. Our probable reserves were 70% natural gas. As a result of our focus on resource plays, our year-end 2009 proved reserve life index was approximately 14 years. Our 2009 production was 257 Bcfe.

2009 Proved Reserves by Area



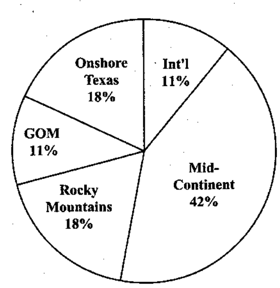
3.6 Tcfe

2009 Probable Reserves by Area



1.9 Tcfe

2010 Estimated Production by Area



278-288 Bcfe

Strategy

Our growth strategy has evolved since our company was founded in 1989 and has allowed us to move into new unconventional plays, lengthen our reserves life and build a portfolio capable of sustainable future growth. Our strategy today consists of the following key elements:

- focusing on unconventional, domestic resource plays of scale, characterized by large acreage positions and deep inventories of low risk drilling opportunities;
- growing reserves through an active drilling program, supplemented with select acquisitions;
- focusing on select geographic areas and allocating capital to the best growth opportunities;
- controlling operations and costs; and
- attracting and retaining a quality workforce through equity ownership and other performance-based incentives.

Focus on Unconventional Resource Plays of Scale. Over the last several years, our industry has increased its focus on unconventional resources. We have been no exception and now own interests in more than 1 million gross acres in resource plays. These plays cover large acreage positions and have years of lower-risk drilling opportunities. Their development allows for efficiency gains in the drilling and completion processes, as well as sustainable and repeatable growth profiles. Our unconventional resource plays include producing positions in the Woodford Shale of Oklahoma, the Granite Wash of Texas, the Uinta Basin of Utah and the Eagle Ford and Pearsall Shales of southwest Texas. We also have leased acreage in the Marcellus Shale of Pennsylvania and the Southern Alberta Basin of Montana.

Drilling Program. The components of our drilling program reflect the significant changes in our asset base over the last few years. To manage the risks associated with our strategy to grow reserves through our drilling programs, a substantial majority of the wells we drilled in 2009 were lower-risk with low to moderate reserve potential. We have lower-risk drilling opportunities in the Mid-Continent, the Rocky Mountains and the shallow waters of Malaysia. These opportunities are complemented with higher-risk, higher reserve potential plays in deepwater areas like the Gulf of Mexico and Malaysia. We actively look for new drilling ideas on our existing property base and on properties that may be acquired.

Acquisitions. Acquisitions have consistently been a part of our strategy, particularly when entering new geographic regions. Since 2000, we have completed five significant acquisitions that led to the establishment of new focus areas onshore in the United States. We actively pursue acquisitions of proved oil and gas properties in select geographic areas, including those areas where we currently focus. The potential to add reserves through drilling is a critical consideration in our acquisition screening process. See "Recent Developments" below.

Geographic Focus. We believe that our long-term success requires extensive knowledge of the geologic and operating conditions in the areas where we operate. Because of this belief, we focus our efforts on a limited number of geographic areas where we can use our core competencies and have a significant influence on operations. Geographic focus also allows more efficient use of capital and personnel.

Control of Operations and Costs. In general, we prefer to operate our properties. By controlling operations, we can better manage production performance, control operating expenses and capital expenditures, consider the application of technologies and influence timing. At year-end 2009, we operated a significant portion of our net total production.

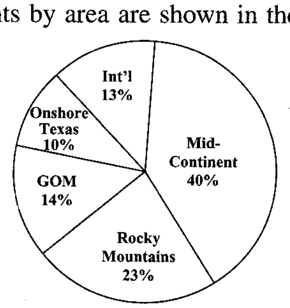
Equity Ownership and Incentive Compensation. We want our employees to act like owners, so we reward and encourage them through equity ownership and performance-based compensation. A large portion of our employees' compensation is tied to our performance.

2010 Outlook and Capital Investments

Our 2010 capital budget is $1.6 billion, including approximately $124 million of estimated capitalized interest and overhead. We expect our 2010 production to grow 8-12% over 2009 levels. Our diversified portfolio of assets provides us with flexibility in our capital allocation process. We have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations.

For 2010, approximately 70% of our natural gas production and 40% of our oil production is hedged. For a complete discussion of our hedging activities, a listing of open contracts as of December 31, 2009 and the estimated fair value of these contracts as of that date, see Note 5, "Derivative Financial Instruments," to our consolidated financial statements.

Our estimated 2010 capital investments by area are shown in the chart below:



$1.6 Billion

Our Properties and Plans for 2010

Resource Plays

A key element of our strategy is to focus on domestic, unconventional resource plays of scale. These plays represent approximately 80% of our proved reserves and 85% of our probable reserves at year-end 2009.

Mid-Continent. Our largest business unit in terms of production, reserves and capital investment is the Mid-Continent. It has been our fastest growing business unit over the last several years. We are focused primarily in the Anadarko and Arkoma Basins. As of December 31, 2009, we owned a working interest in approximately 725,000 gross acres (approximately 400,000 net acres) and approximately 2,300 gross producing wells. This region is characterized by longer-lived natural gas production.

Woodford Shale. Our largest single investment area over the last several years has been the Woodford Shale in our Mid-Continent division, located in the Arkoma Basin of southeast Oklahoma. The Woodford is a shale formation that varies in thickness from 100 to 200 feet throughout our acreage. Our activities began in this area in 2003. At year-end 2009, we owned an interest in approximately 166,500 net acres. Our average working interest is approximately 60%. Since 2003, we have drilled more than 100 vertical wells and approximately 300 horizontal wells. We are currently running eight operated rigs on the acreage and expect to run six to eight operated rigs throughout 2010.

Our 2009 production in the Woodford Shale was 26% higher than our 2008 production, despite voluntary curtailments of approximately 3 Bcfe of natural gas production related to low gas prices in the second half of 2009. As of February 15, 2010, our operated production in the Woodford Shale was approximately 190 MMcfe/d net.

We expect our production in the Woodford Shale to grow more than 25% during 2010. Substantially all of our acreage is held-by-production. Our development plans for the field include drilling several thousand wells on primarily 40-acre spacing. We have improved efficiencies in the play through the drilling of horizontal wells with longer lateral completions. Our average lateral length has doubled since 2006 to a 2009 average of approximately 5,000', and we expect our average length to be approximately 6,000' in 2010.

Granite Wash. We are active in the Granite Wash play located in the Anadarko Basin of northern Texas and western Oklahoma and have more than 44,000 net acres in the play. Our largest producing field in the Granite Wash is Stiles/Britt Ranch, where we operate and own an average 75% working interest. Although we have approximately 150 producing vertical wells in Stiles/Britt Ranch, our recent efforts have shifted to horizontal drilling. Since late 2008, we have drilled and completed 13 horizontal wells in the Granite Wash and the average initial production for these wells was approximately 20 MMcfe/d (gross). During 2009, we ran three to four operated drilling rigs in the field with production as of February 15, 2010 of approximately 130 MMcfe/d net. We expect to continue this level of activity in the Granite Wash, and expect our production in the Granite Wash to grow more than 25% during 2010. We have an inventory of approximately 250 locations in the Granite Wash.

Rocky Mountains. As of December 31, 2009, we owned an interest in approximately 1.4 million gross acres (1 million net acres) and more than 2,400 gross producing wells in the Rocky Mountains. Our assets in the Rocky Mountains are more than 70% oil and have long-lived production. Our efforts today are focused primarily on oil plays in the Uinta, Williston and Southern Alberta Basins.

Monument Butte. Our largest asset in the Rocky Mountains is the Monument Butte oil field, located in the Uinta Basin of Utah. Our working interest in the field averages about 80% and we operate the field, which is substantially held-by-production. The field accounted for approximately 20% of our year-end 2009 proved reserves. We have approximately 1,300 productive oil wells in Monument Butte. Our acreage in this region is approximately 180,000 net acres. This includes 63,000 net acres that we have added over the last two years through several transactions with Ute Energy LLC. These lands adjoin Monument Butte at the field's northern edge. Since 2008, we have drilled approximately 75 wells on the Ute acreage. Our gross production from the Monument Butte field area has grown from 7,000 BOPD in 2004 to a February 15, 2010 rate of approximately 17,000 BOPD gross. In 2010, we are planning to drill a substantial portion of the acreage on 20-acre development spacing and estimate that we have thousands of remaining locations in the Monument Butte field area. There is a significant gas resource beneath the shallow producing oil zones at Monument Butte. In 2008, we participated in the drilling of six successful deep test wells to evaluate these deeper formations. Our 2010 plans include drilling our first horizontal well to test these deep gas objectives beneath Monument Butte.

Williston Basin/Southern Alberta Basin. We have approximately 150,000 net acres in the Williston Basin, excluding approximately 54,000 net acres in the mature Elm Coulee field. To date, we have drilled 14 successful wells with production from the Bakken and Sanish/Three Forks formations. Our production at year-end 2009 was approximately 2,500 BOEPD net. We plan to run three operated rigs in 2010 and expect production in the Williston Basin to grow more than 40% during the year. We have an inventory of approximately 80 development locations primarily along the Nesson Anticline. In late 2009, we reached an agreement with the Blackfeet Nation covering approximately 156,000 net acres in the Southern Alberta Basin of northern Montana. Including this recent transaction, we now have approximately 221,000 net acres in the Southern Alberta Basin. Our 2010 plans include drilling up to 10 wells in the Southern Alberta Basin.

Green River Basin. We own interests in 4,000 net acres in the Pinedale Field, located in Sublette County, Wyoming and operate our activities in Pinedale. We also have an interest in the Jonah field, located in Sublette County, Wyoming, where we have identified about 35 development locations on 10- and 5-acre well spacing. Although we halted our activities in the Green River Basin with lower gas prices in 2009, we see the potential to drill approximately 120 additional locations as field spacing decreases to 20 acres and eventually to 10 acres. With improved realized gas prices in 2010, our activities here may resume in 2010.

Appalachia. In mid-2009, we signed a joint exploration agreement with Hess Corporation covering up to 140,000 gross acres in the Marcellus Shale play, primarily in Wayne County, Pennsylvania. We are the operator of this venture with a 50% working interest. At year-end 2009, we had leased about 35,000 net acres. This marked our entry into the Marcellus — one of the nation's largest resource plays. The Marcellus is economically advantaged due to its close proximity to the gas markets of the Northeast. We are permitting our initial wells and expect to drill 6-10 assessment wells in 2010 to test for commercial quantities of gas, evaluate acreage and core data while determining how best to develop our acreage.

Conventional Plays

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

Onshore Texas. As of December 31, 2009, we owned an interest in approximately 375,000 gross acres (224,000 net) and about 750 gross producing wells onshore Texas. We slowed our activities in many of our conventional natural gas plays onshore Texas in 2009 in response to lower natural gas prices. At year-end 2009, we were producing approximately 170 MMcfe/d net from our onshore Texas assets. With planned decreased investments in 2010 and natural declines, we expect production from this area to decline approximately 15% during 2010. However, production from our recently acquired assets from TXCO Resources Inc. ("TXCO") will add to our production, which should cause our 2010 production from onshore Texas to remain relatively flat. Our acquisition of assets from TXCO was our entry into the Maverick Basin of southwest Texas. We have multiple potential geologic targets for future development, primarily in the Eagle Ford and Pearsall Shales. See "Recent Developments" below.

Gulf of Mexico. Our Gulf of Mexico operations are focused on the deepwater. At year-end 2009, our daily production from the Gulf of Mexico was approximately 90 MMcfe/d net. We have five active deepwater developments underway that we expect will lead to significant future production growth. As of December 31, 2009, we owned interests in 86 deepwater leases and approximately 370,000 net acres. We have an inventory of prospects acquired primarily through federal lease sales over the last several years and we expect to drill three to five wells per year for the next several years. Our working interests typically range from 20-50%. We expect our Gulf of Mexico production to grow more than 60% during 2010.

International. Our international activities are focused in Southeast Asia. We have production and active developments offshore Malaysia and China. Our international production at year-end 2009 was approximately

17,000 BOPD net. We have an interest in approximately 3 million acres gross (1.1 million net) offshore Malaysia and approximately 1.7 million acres gross (1.6 million net) offshore China. In 2010, our plans include continued development of our oil fields offshore Malaysia. During 2010, we also plan to develop our 2009 "Pearl" discovery in the Pearl River Mouth Basin of China and plan to drill two exploratory commitment wells offshore China. We expect our international production to decline approximately 20% in 2010.

Recent Developments

On February 11, 2010, we acquired certain of TXCO's assets in the Maverick Basin of southwest Texas for $215 million. The assets we acquired include approximately 300,000 net acres and current net production of approximately 1,500 BOEPD, of which approximately two-thirds is oil.

Concentration

Reserves. The table below sets forth the concentration of our proved and probable reserves, by location, and the percentage of those reserves attributable to our largest fields. Our largest fields, the Woodford Shale and Monument Butte, accounted for about 40% of the total net present value of our proved reserves at December 31, 2009.

	Percentage of Proved Reserves	Percentage of Probable Reserves
Located domestically	95	92
Located onshore	90	88
10 largest fields	85	94
2 largest fields	64	80

Oil and Gas Production, Prices and Costs. The table below sets forth for our largest fields (those whose reserves are greater than 15% of our total proved reserves) the annual production volumes, 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, realized prices and related production cost structure on a per unit of production basis, see Item 7, *"Management's Discussion and Analysis of Financial Condition and Results of Operations* — Results of Operations."

	Year Ended December 31,		
	2009	2008	2007
Production:			
Natural gas (Bcf)			
Monument Butte	4.5	5.1	5.2
Woodford Shale	61.4	52.1	23.8
Oil and condensate (MBbls)			
Monument Butte	4,080	3,471	2,859
Woodford Shale	37	10	4
Average Realized Prices:			
Natural gas (per Mcf)			
Monument Butte	$ 2.80	$ 3.62	$ 2.19
Woodford Shale	$ 3.19	$ 6.66	$ 5.67
Oil and condensate (per Bbl)			
Monument Butte	$48.21	$81.48	$56.61
Woodford Shale	$53.49	$97.23	$68.00
Production Cost:			
Monument Butte (per BOE)	$ 7.65	$ 9.66	$ 6.83
Woodford Shale (per Mcfe)	$ 0.82	$ 1.06	$ 1.20

Proved and Probable Reserves

All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. The preparation of our oil and gas reserves estimates is completed in accordance with our prescribed internal control procedures, which include verification of data input into reserves forecasting and economics evaluation software, as well as multi-discipline management reviews, as described below. The technical employee responsible for overseeing the preparation of the reserves estimates has a Bachelor of Science in Petroleum Engineering, with more than 25 years of experience (including 15 years of experience in reserve estimation) and is a Registered Professional Engineer in Texas.

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

Actual quantities of reserves recovered will most likely vary from the estimates set forth below. Reserves and cash flow estimates rely on interpretations of data and require assumptions that may be inaccurate. For a discussion of these interpretations and assumptions, see *"Actual quantities of oil and gas reserves and future cash flows from those reserves will most likely vary from our estimates"* under Item 1A of this report. Our estimates of proved reserves, proved developed reserves and proved undeveloped reserves and future net cash flows and discounted future net cash flows from proved reserves at December 31, 2009, 2008 and 2007 and changes in proved reserves during the last three years are contained in "Supplementary Financial Information — Supplementary Oil and Gas Disclosures — Estimated Net Quantities of Proved Oil and Gas Reserves" in Item 8 of this report. For a discussion of the significant changes in our proved reserves during 2009, please see the information set forth in *"Management's Discussion and Analysis of Financial Condition and Results of Operations* — Proved Reserves" in Item 7 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, 2009.

	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	Total (Bcfe)(1)
Proved Developed Reserves:			
Domestic	70	1,397	1,820
International:			
Malaysia	10	—	60
China	5	—	28
Total International	15	—	88
Total Proved Developed	85	1,397	1,908
Proved Undeveloped Reserves:			
Domestic	66	1,208	1,604
International:			
Malaysia	16	—	91
China	2	—	13
Total International	18	—	104
Total Proved Undeveloped	84	1,208	1,708
Total Proved Reserves	169	2,605	3,616
Probable Developed Reserves:			
Domestic	9	29	83
International:			
Malaysia	3	—	18
China	—	—	—
Total International	3	—	18
Total Probable Developed	12	29	101
Probable Undeveloped Reserves:			
Domestic	62	1,293	1,667
International:			
Malaysia	4	—	25
China	17	—	100
Total International	21	—	125
Total Probable Undeveloped	83	1,293	1,792
Total Probable Reserves	95	1,322	1,893

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

Proved Reserves. Our year-end 2009 proved reserves of 3.6 Tcfe increased 23% as compared to our proved reserves at year-end 2008, and consisted of 1,505 Bcfe proved developed producing, 403 Bcfe proved developed non-producing and 1,708 Bcfe proved undeveloped reserves. Our 2009 proved reserves include 693 Bcfe of additions resulting from the change in the Securities and Exchange Commission ("SEC") definition of proved reserves, expanding proved undeveloped reserve locations beyond one direct offset away from producing wells if such locations meet the definition of proved reserves.

At December 31, 2008 our estimated proved undeveloped reserves were 1,124 Bcfe. During 2009, we spent $364 million of drilling, completion and facilities-related capital to convert 123 Bcfe of our December 31, 2008 proved undeveloped reserves into proved developed reserves. Another 275 Bcfe of our beginning of year proved undeveloped reserves were removed from the proved undeveloped category during 2009, substantially all of which were no longer economic utilizing a natural gas price of $3.87 per MMBtu for our year-end 2009 reserve calculations. During 2009, we added 289 Bcfe of new proved undeveloped reserves through drilling activities. Additionally, we added 693 Bcfe of proved undeveloped reserves as a result of the change in the SEC definition of proved reserves expanding proved undeveloped reserve locations beyond one direct offset away from producing wells. These additions were primarily in our Woodford Shale and Monument Butte fields. Proved undeveloped reserve quantities were limited by the activity level of development drilling we expect to undertake during the 2010-2014 five-year period. Quantities of reserves that would otherwise meet the definition of proved undeveloped reserves except for the fact that they will be developed beyond the 2010-2014 five-year horizon (904 Bcfe) have been classified as probable reserves, in accordance with SEC regulations. As a result of the foregoing, our proved undeveloped reserves at December 31, 2009 were 1,708 Bcfe, 98% of which have been included in our reserve report for less than five years. For additional information regarding the changes in our proved reserves, see "Proved Reserves" under Item 7 of this report.

Probable Reserves. Our probable reserves at year-end 2009 consisted of 101 Bcfe developed and 1,792 Bcfe of undeveloped reserves. Included in our undeveloped probable reserves are 904 Bcfe that would otherwise meet the definition of proved undeveloped reserves except for the fact that they will not be developed during the 2010-2014 five-year horizon. A significant portion of these probable reserves are associated with our Woodford Shale activities.

Reserves Sensitivities. To determine our year-end 2009 reserves estimates, we utilized the unweighted average first-day-of-the-month natural gas and crude oil prices for the prior twelve months, or $3.87 per MMBtu and $61.14 per barrel, respectively, adjusted for market differentials. In 2009, we experienced low average natural gas prices and, as a result, the estimated future net cash flows from our proved reserves are substantially lower than at year-end 2008 on a unit-of-reserve basis, but are substantially offset by higher quantities of proved reserves. The table below illustrates changes in the quantities of proved and probable reserves at various price scenarios, holding all other year-end reserve assumptions constant.

	Proved Reserves			Probable Reserves		
Price Case	**Oil**	**Natural Gas**	**Total**	**Oil**	**Natural Gas**	**Total**
($/MMBtu for Natural Gas and $/Bbl for Oil)	**(MBbls)**	**(Bcf)**	**(Bcfe)**	**(MBbls)**	**(Bcf)**	**(Bcfe)**
Assumed $3.87 and $50	164	2,597	3,582	92	1,317	1,870
Pricing per SEC rules $3.87 and $61.14	**169**	**2,605**	**3,616**	**95**	**1,323**	**1,893**
Assumed $3.87 and $70	170	2,609	3,630	94	1,323	1,886
Assumed $5 and $61.14	169	2,758	3,774	95	1,821	2,393

Our proved reserves increase at higher prices primarily as a result of extending the economic life of our proved developed reserves. Higher realized prices do not materially increase the quantity of our proved undeveloped reserves because it is limited by the level of development drilling we expect to undertake during the 2010-2014 five-year period. This limitation impacts our Woodford Shale (natural gas) and our Monument Butte field (crude oil) developments because of their size.

Our probable reserves increase approximately 500 Bcfe utilizing a $5.00 per MMBtu natural gas price instead of a $3.87 per MMBtu natural gas price, with no change in oil prices. The increase is attributable to quantities of reserves associated with our Woodford Shale activities that are not commercial at a $3.87 per MMBtu natural gas price. These probable reserves would meet the definition of proved undeveloped reserves except for the fact that they would be developed beyond the 2010-2014 five-year horizon. Accordingly, a total of approximately 1,404 Bcfe, or 60%, of our probable reserves at a $5.00 per MMBtu natural gas price would meet the definition of proved undeveloped reserves except for the fact that they would be developed beyond the 2010-2014 five-year horizon.

Our proved reserves decrease at lower crude oil prices as a result of shortening the economic life of our proved developed reserves. Crude oil prices at the levels shown in the table above would not change our development plans and, therefore, have no impact on the quantity of proved undeveloped reserves because that quantity is limited by the level of development drilling we expect to undertake during the 2010-2014 five-year period. Our proved undeveloped oil reserves lie primarily in our Monument Butte field.

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

Drilling Activity

The following table sets forth our drilling activity for each year (other than drilling activity related to our operations in the United Kingdom, which were discontinued in 2007) in the three-year period ended December 31, 2009.

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Domestic:						
Productive[1]	273	153.1	385	217.4	343	219.0
Nonproductive[2]	8	4.8	20	15.4	24	16.6
International:						
China:						
Productive[3]	1	1.0	2	1.1	—	—
Nonproductive[4]	—	—	1	1.0	—	—
Malaysia:						
Productive[5]	1	0.4	5	2.6	1	0.6
Nonproductive[6]	—	—	—	—	3	2.1
International Total:						
Productive	2	1.4	7	3.7	1	0.6
Nonproductive	—	—	1	1.0	3	2.1
Exploratory well total	283	159.3	413	237.5	371	238.3
Development wells:						
Domestic:						
Productive	128	98.7	175	138.2	135	105.7
Nonproductive	—	—	4	3.0	2	1.6
International:						
China:						
Productive	12	1.4	6	0.7	8	1.0
Nonproductive	—	—	2	0.2	—	—
Malaysia:						
Productive	5	2.8	7	4.2	3	1.7
Nonproductive	—	—	—	—	—	—
International Total:						
Productive	17	4.2	13	4.9	11	2.7
Nonproductive	—	—	2	0.2	—	—
Development well total	145	102.9	194	146.3	148	110.0

(1) Includes 29 gross (17.7 net), 38 gross (27.1 net) and 19 gross (12 net) wells in 2009, 2008 and 2007, respectively, that are not exploitation wells.

(2) Includes 3 gross (1.3 net), 9 gross (7.5 net) and 15 gross (8.8 net) wells in 2009, 2008 and 2007, respectively, that are not exploitation wells.

(3) Includes 1 gross (1.0 net) well in each of 2009 and 2008 that is not an exploitation well.

(4) The well in 2008 is not an exploitation well.

(5) Includes 1 gross (0.4 net) and 2 gross (1.1 net) wells in 2009 and 2008, respectively, that are not exploitation wells.

(6) Includes 3 gross (2.1 net) wells in 2007 that are not exploitation wells.

We were in the process of drilling 36 gross (21.0 net) exploratory wells (includes 32 gross (18.6 net) exploitation wells) and 11 gross (8.2 net) development wells domestically at December 31, 2009. Internationally, we were drilling 1 gross (1.0 net) exploratory well in China at December 31, 2009. This well is not an exploitation well.

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, 2009 and the location of, and other information with respect to, those wells. As of December 31, 2009, we had 67 gross (53.4 net) gas wells and 5 gross (2.5 net) oil wells with multiple completions.

	Company Operated Wells		Outside Operated Wells		Total Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
Domestic:						
Offshore:						
Oil	—	—	2	0.5	2	0.5
Natural gas	5	3.3	2	0.6	7	3.9
Onshore:						
Oil	2,475	2,021.2	232	42.2	2,707	2,063.4
Natural gas	1,523	1,199.7	1,269	276.5	2,792	1,476.2
Total Domestic:						
Oil	2,475	2,021.2	234	42.7	2,709	2,063.9
Natural gas	1,528	1,203.0	1,271	277.1	2,799	1,480.1
International:						
Offshore China:						
Oil	—	—	34	4.1	34	4.1
Offshore Malaysia:						
Oil	12	7.2	22	11.0	34	18.2
Total International:						
Oil	12	7.2	56	15.1	68	22.3
Total:						
Oil	2,487	2,028.4	290	57.8	2,777	2,086.2
Natural gas	1,528	1,203.0	1,271	277.1	2,799	1,480.1
Total	4,015	3,231.4	1,561	334.9	5,576	3,566.3

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

Acreage Data

As of December 31, 2009, we owned interests in developed and undeveloped oil and gas acreage set forth in the table below. Domestic ownership interests generally take the form of "working interests" in oil and gas leases that have varying terms. International ownership interests generally arise from participation in production sharing contracts.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
	(In thousands)			
Domestic:				
Offshore	71	13	667	357
Onshore:				
Mid-Continent	612	340	115	53
Rocky Mountains	197	118	1,243	923
Gulf Coast	143	97	237	129
Appalachia	—	—	70	35
Total Onshore	952	555	1,665	1,140
Total Domestic	1,023	568	2,332	1,497
International:				
Offshore China	22	3	1,674	1,674
Offshore Malaysia	190	96	2,604	1,029
Total International	212	99	4,278	2,703
Total	1,235	667	6,610	4,200

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 374,480 gross (107,040 net) undeveloped acres. These interests do not expire.

	Undeveloped Acres Expiring									
	2010		2011		2012		2013		2014	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(In thousands)									
Domestic:										
Offshore	107	31	23	19	63	21	103	82	40	20
Onshore:										
Mid-Continent	230	27	87	8	188	17	19	1	1	—
Rocky Mountains	349	289	200	155	63	51	31	20	38	27
Gulf Coast	105	52	47	20	15	9	18	14	7	5
Total Onshore	684	368	334	183	266	77	68	35	46	32
Total Domestic	791	399	357	202	329	98	171	117	86	52
International:										
Offshore China	1,292	1,292	—	—	—	—	382	382	—	—
Offshore Malaysia	338	203	1,079	431	—	—	1,187	395	—	—
Total International	1,630	1,495	1,079	431	—	—	1,569	777	—	—
Total	2,421	1,894	1,436	633	329	98	1,740	894	86	52

Title to Properties

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

Marketing

Substantially all of our oil and gas production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market sensitive prices. For a list of purchasers of our oil and gas production that accounted for 10% or more of our consolidated revenue for the three preceding calendar years, please see Note 1, "Organization and Summary of Significant Accounting Policies — *Major Customers*," to our consolidated financial statements. 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 Monument Butte field oil production. Due to the higher paraffin content of this production, there is limited refining capacity for it. Please see the discussion under *"There is limited refining capacity for our black wax crude oil, which may limit our ability to sell our current production or to increase our production at Monument Butte 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 in the Gulf of Mexico. For a further discussion, please see the information regarding competition set forth in Item 1A of this report.

Employees

As of February 22, 2010, we had 1,148 employees. All but 101 of our employees were located in the U.S. 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 that can affect the cost, manner or feasibility of doing business. In addition, potential regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business."* in Item 1A of this report.

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 ("NGA") and by regulations and orders promulgated under the NGA by the FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations. The Outer Continental Shelf Lands Act, or OCSLA, requires that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its Natural Gas Act jurisdiction. Therefore, we do not believe that any FERC or MMS action taken under OCSLA will affect us in a way that materially differs from the way it will affect other natural gas producers, gatherers and marketers with which we compete.

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

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

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

Federal Regulation of Sales and Transportation of Crude Oil. Our sales of crude oil and condensate are currently not regulated. In a number of instances, however, the ability to transport and sell such products are 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.

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

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

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

State and Local Regulation of Drilling and Production. We own interests in properties located onshore in a number of states and in state waters offshore Texas and Louisiana. 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.

Environmental Regulations. Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. 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). Environmental laws and regulations are complex, and have tended to become more stringent over time. We also are subject to various environmental permit requirements. Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted. Moreover, some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts onshore or offshore drilling or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected.

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

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

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

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

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

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

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

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

Congress has been actively considering legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs. In June of 2009, the U.S. House of Representatives passed a cap and trade bill known as the American Clean Energy and Security Act of 2009, which is now being considered by the U.S. Senate. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of 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 finding that the current and projected concentrations of greenhouse gases 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. EPA published the final version of this finding on December 15, 2009, which allowed EPA to proceed with the rulemaking process to regulate greenhouse gases under the Clean Air Act. In anticipation of the finalization of EPA's finding that greenhouse gases threaten public health and welfare, and that greenhouse gases from new motor vehicles contribute to climate change, EPA proposed a rule in September of 2009 that would require a reduction in emissions of greenhouse gases from motor vehicles and would trigger applicability of Clean Air Act permitting requirements for certain stationary sources of greenhouse gas emissions. In response to this issue, EPA also proposed a tailoring rule that would, in general, only impose greenhouse gas permitting requirements on facilities that emit more than 25,000 tons per year of greenhouse gases. Moreover, on September 22, 2009, EPA finalized a rule requiring nation-wide reporting of greenhouse gas emissions in 2011 for emissions occurring in 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year, and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines. Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted to address 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.

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

Commonly Used Oil and Gas Terms

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

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

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

Bcf. Billion cubic feet.

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

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

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

BOEPD. Barrels of oil equivalent per day.

BOPD. Barrels of oil per day.

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

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

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

Developed acreage. 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.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploitation well. An exploration well drilled to find and produce probable reserves. Most of the exploitation wells we drilled in 2007, 2008 and 2009 and expect to drill in 2010 are located in the Mid-Continent or the Monument Butte field. Exploitation wells in those areas have less risk and less reserve potential and typically may be drilled at a lower cost than other exploration wells. For internal reporting and budgeting purposes, we combine exploitation and development activities.

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

FERC. The Federal Energy Regulatory Commission.

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

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

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

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

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

Mcf. One thousand cubic feet.

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

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

MMS. The Minerals Management Service of the United States Department of the Interior.

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

MMBtu. One million Btus.

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

NYMEX. The New York Mercantile Exchange.

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

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

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

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

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

Proved undeveloped reserves. In general, proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

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

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

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

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

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

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

Item 1A. *Risk Factors*

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

Oil and gas prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse impact on our business. Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas. Lower prices may reduce the amount of oil and gas that we can economically produce. Oil and gas prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount that we can borrow under our credit facility could be limited by changing expectations of future prices because the maximum amount that we may borrow under our credit facility is determined by our lenders annually each May, and may be adjusted at the option of our lenders in the case of certain acquisitions or divestitures, using a process that takes into account the value of our estimated reserves and hedge position and the lenders' commodity price assumptions.

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

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

We have substantial capital requirements to fund our business plans, and a slow recovery of the economy and the financial markets in 2010 or another decline or crisis as was experienced in late 2008 and 2009 could negatively impact our ability to execute our business plan. Although we anticipate that our 2010 capital spending, excluding acquisitions, will correspond with our anticipated 2010 cash flows, we may borrow and repay funds under our credit arrangements throughout the year since the timing of expenditures and the receipt of cash flows from operations do not necessarily match. Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We may have to reduce capital expenditures, and our ability to execute our business plans could be adversely affected, if (1) one or more of the lenders under our existing credit arrangements fail to honor its contractual obligation to lend to us, (2) the amount that we are allowed to borrow under our existing credit facility is reduced as a result of lower oil and gas prices, declines in reserves, lending requirements or for other reasons or (3) our customers or working interest owners default on their obligations to us.

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

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

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

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

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

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

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

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

There is limited refining capacity for our black wax crude oil, which may limit our ability to sell our current production or to increase our production at Monument Butte in the Uinta Basin. Most of the crude oil we produce in the Uinta Basin is known as "black wax" because it has higher paraffin content than crude oil found in most other major North American basins. Due to its wax content, it must remain heated during shipping, so the oil is transported by truck to refiners in the Salt Lake City area. We currently have agreements in place with area refiners that secure base load sales of substantially all of our expected production in the Uinta Basin through the end of 2010. In the current economic environment, there is a risk that they may fail to satisfy their obligations to us under those contracts. During the fourth quarter of 2008, the largest purchaser of our black wax crude oil failed to pay for certain deliveries of crude oil and filed for bankruptcy protection. Although we continue to sell our black wax crude oil to that purchaser on a short-term basis that provides for more timely cash payments, we cannot guarantee that we will be able to continue to sell to this purchaser or that similar substitute arrangements could be made for sales of our black wax crude oil with other purchasers if desired. An extended loss of our largest purchaser could have a material adverse effect on us because there are limited purchasers of our black wax crude. We continue to work with refiners to expand the market for our existing black wax crude oil production and to secure additional capacity to allow for production growth. However, without additional refining capacity, our ability to increase production from the field may be limited.

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." As of December 31, 2008, we recorded a $1.8 billion ($1.1 billion after-tax) ceiling test writedown. We recorded an additional $1.3 billion ($854 million after-tax) ceiling test writedown as of March 31, 2009. Although a ceiling test writedown does not impact cash flow 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.

The risk that we will be required to further write down 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. We may experience further ceiling test writedowns or other impairments in the future. In addition, 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 often are uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- costs of, or shortages or delays in the availability of, drilling rigs, equipment and materials;
- adverse weather conditions and changes in weather patterns;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- embedded oilfield drilling and service tools;
- equipment failures or accidents;
- lack of necessary services or qualified personnel;
- availability and timely issuance of required governmental permits and licenses;

- availability, costs and terms of contractual arrangements, such as leases, pipelines and related facilities to gather, process and compress, transport and market natural gas, crude oil and related commodities; and
- compliance with, or changes in, environmental, tax and other laws and regulations.

The oil and gas business involves many operating risks that can cause substantial losses, and insurance may not protect us against all of these risks. We are not insured against all risks. 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, formation water or drilling fluids;
- adverse weather conditions or natural disasters;
- pipe or cement failures and casing collapses;
- pipeline ruptures;
- discharges of toxic gases;
- build up of naturally occurring radioactive materials; and
- vandalism.

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;
- suspension of our operations; and
- repairs to resume operations.

If we experience any of these problems, our ability to conduct operations could be adversely affected.

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

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not insurable.

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

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

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

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

In addition, changes to existing regulations or the adoption of new regulations may unfavorably impact us, our suppliers or our customers. For example, governments around the world have become increasingly focused on climate change matters. In the United States, legislation that directly impacts our industry has been proposed covering areas such as emission reporting and reductions, hydraulic fracturing, the repeal of certain oil and gas tax incentives and tax deductions, and the regulation of over-the-counter commodity hedging activities. These and other potential regulations 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.

Congress has been actively considering legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs. In June of 2009, the U.S. House of Representatives passed a cap and trade bill known as the American Clean Energy and Security Act of 2009, which is now being considered by the U.S. Senate. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of 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 finding that the current and projected concentrations of greenhouse gases 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. EPA published the final version of this finding on December 15, 2009, which allowed EPA to proceed with the rulemaking process to regulate greenhouse gases under the Clean Air Act. In anticipation of the finalization of EPA's finding that greenhouse gases threaten public health and welfare, and that greenhouse gases from new motor vehicles contribute to climate change, EPA proposed a rule in September of 2009 that would require a reduction in emissions of greenhouse gases from motor vehicles and would trigger applicability of Clean Air Act permitting requirements for certain stationary sources of greenhouse gas emissions. In response to this issue, EPA also proposed a tailoring rule that would, in general, only impose greenhouse gas permitting requirements on facilities that emit more than 25,000 tons per year of greenhouse gases. Moreover, on September 22, 2009, EPA finalized a rule requiring nation-wide reporting of greenhouse gas emissions in 2011 for emissions occurring in 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year, and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines. Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted to address 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.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control. The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. We deliver oil and gas through gathering systems and pipelines that we do not own. The lack of availability of capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our production through some firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical or other reasons, or may not be available to us in the future at a price that is acceptable to us. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition, results of operations and cash flows.

We have risks associated with our non-U.S. operations. Ownership of property interests and production operations in areas outside the United States is 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;
- increases in taxes and governmental royalties;
- forced renegotiation of, or unilateral changes to, or termination of contracts with governmental entities and quasi-governmental agencies;
- changes in laws and policies governing operations of non-U.S. based companies;
- our limited ability to influence or control the operation or future development of these non-operated properties;
- the operator's expertise or other labor problems;
- difficulties enforcing our rights against a governmental entity because of the doctrine of sovereign immunity and foreign sovereignty over international operations; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

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

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

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

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

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

There is competition for available oil and gas properties. Our competitors include major oil and gas companies, independent oil and gas companies and financial buyers. Some of our competitors may have greater and more diverse resources than we do. High commodity prices and stiff competition for acquisitions have in the past, and may in the future, significantly increase the cost of available properties.

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

Item 1B. *Unresolved Staff Comments*

None.

Item 3. *Legal Proceedings*

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

Item 4. *Submission of Matters to a Vote of Security Holders*

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

Executive Officers of the Registrant

The following table sets forth the names of, ages (as of February 22, 2010) 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	48	President and Chief Executive Officer and Director	10
Gary D. Packer	47	Executive Vice President and Chief Operating Officer	14
Terry W. Rathert	57	Executive Vice President and Chief Financial Officer	20
Mona Leigh Bernhardt	43	Vice President — Human Resources	10
W. Mark Blumenshine	51	Vice President — Land	8
Stephen C. Campbell	41	Vice President — Investor Relations	10
George T. Dunn	52	Vice President — Mid-Continent	17
Daryll T. Howard	47	Vice President — Rocky Mountains	13
John H. Jasek	40	Vice President — Gulf of Mexico	10
Samuel E. Langford	52	Vice President — Corporate Development	5
James J. Metcalf	52	Vice President — Drilling	14
William D. Schneider	58	Vice President — Onshore Gulf Coast and International	21
Michael D. Van Horn	58	Vice President — Geoscience	3
James T. Zernell	52	Vice President — Production	12
John D. Marziotti	46	General Counsel and Secretary	6
Brian L. Rickmers	41	Controller and Assistant Secretary	16
Susan G. Riggs	52	Treasurer	12

The executive officers have held the positions indicated above for the past five years, except as follows:

Lee K. Boothby was promoted to the position of President on February 5, 2009 and to the additional role of Chief Executive Officer on May 7, 2009. Our Board of Directors also has named Mr. Boothby to the additional role of Chairman of the Board, effective May 7, 2010 if he is re-elected as a director at our annual meeting on that date. Prior to February 5, 2009, Mr. Boothby served as Senior Vice President — Acquisitions & Business Development since October 2007. He managed our Mid-Continent operations from February 2002 to October 2007, and was promoted from General Manager to Vice President in November 2004.

Gary D. Packer was promoted to the position of Executive Vice President and Chief Operating Officer on May 7, 2009. Prior thereto, he was promoted from Gulf of Mexico General Manager to Vice President — Rocky Mountains in November 2004.

Terry W. Rathert was promoted from Senior Vice President to Executive Vice President on May 7, 2009 and previously was promoted from Vice President to Senior Vice President in November 2004. He also served as Secretary of our company until May 2008.

Mona Leigh Bernhardt was promoted from Manager to Vice President in December 2005.

W. Mark Blumenshine was promoted from Manager to Vice President in December 2005.

Stephen C. Campbell was promoted from Manager to Vice President in December 2005.

George T. Dunn was named Vice President — Mid-Continent in October 2007. He managed our onshore Gulf Coast operations from 2001 to October 2007, and was promoted from General Manager to Vice President in November 2004.

Daryll T. Howard was promoted to the position of Vice President — Rocky Mountains on May 7, 2009. Mr. Howard joined Newfield in 1996. Prior to his promotion on May 7, 2009, Mr. Howard served as East Team Rocky Mountain Asset Manager since June 2008. Prior thereto, Mr. Howard assisted in establishing Newfield's Malaysia office and was instrumental in the success and growth of Newfield's international operations. Mr. Howard also previously held several positions of increasing breadth and responsibility in Newfield's Gulf of Mexico organization.

John H. Jasek was reappointed as Vice President — Gulf of Mexico in December 2008. Prior to that, he served as Vice President — Gulf Coast since October 2007 and became the manager of our onshore Gulf Coast operations at that time. 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.

Samuel E. Langford was promoted to the position of Vice President — Corporate Development on May 7, 2009. Mr. Langford joined Newfield in 2004. Prior to his promotion on May 7, 2009, Mr. Langford served as Manager — Acquisitions, Planning and Commercial Development of Newfield's Mid-Continent division since April 2004.

James J. Metcalf was promoted from Manager to Vice President in December 2005.

William D. Schneider was named Vice President — Onshore Gulf Coast and International in December 2008. He has managed our international operations since May 2000.

Michael D. Van Horn joined our company as Senior Vice President — Exploration in November 2006 and became our Vice President — Geoscience on May 7, 2009. He served at EOG Resources, and its predecessor Enron Oil and Gas, from 1993 to November 2006. Most recently, he served as their Vice President of International Exploration. Prior to that position, he was Director of Exploration.

James T. Zernell was promoted from Manager to Vice President in December 2005.

John D. Marziotti was promoted to General Counsel in August 2007 and was named Secretary in May 2008. From November 2003, when he joined our company, until August 2007 he held the position of Legal Counsel. Prior to joining us, he was a shareholder of the law firm of Strasburger & Price, LLP.

PART II

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

Market for Common Stock

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

	High	Low
2008:		
First Quarter	$57.75	$44.15
Second Quarter	69.77	51.88
Third Quarter	68.31	28.00
Fourth Quarter	31.28	15.45
2009:		
First Quarter	$26.50	$17.09
Second Quarter	38.74	21.65
Third Quarter	46.62	27.92
Fourth Quarter	51.27	39.26
2010:		
First Quarter (through February 22, 2010)	$54.07	$47.47

On February 22, 2010, the last reported sales price of our common stock on the NYSE was $49.34. As of that date, there were approximately 2,480 holders of record of our common stock.

Dividends

We have not paid any cash dividends on our common stock and do not intend to do so in the foreseeable future. We intend to retain earnings for the future operation and development of our business. Any future cash dividends to holders of our common stock would depend on future earnings, capital requirements, our financial condition and other factors determined by our Board of Directors. The covenants contained in our credit facility and in the indentures governing our 6⅝% Senior Subordinated Notes due 2014 and 2016, our 7⅛% Senior Subordinated Notes due 2018 and our 6⅞% Senior Subordinated Notes due 2020 could restrict our ability to pay cash dividends. See "Contractual Obligations" under Item 7 of this report and Note 9, "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, 2009.

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, 2009	1,897	$42.03	—	—
November 1 — November 30, 2009	8,961	42.41	—	—
December 1 — December 31, 2009	12,015	43.12	—	—
Total	22,873	$42.75	—	—

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

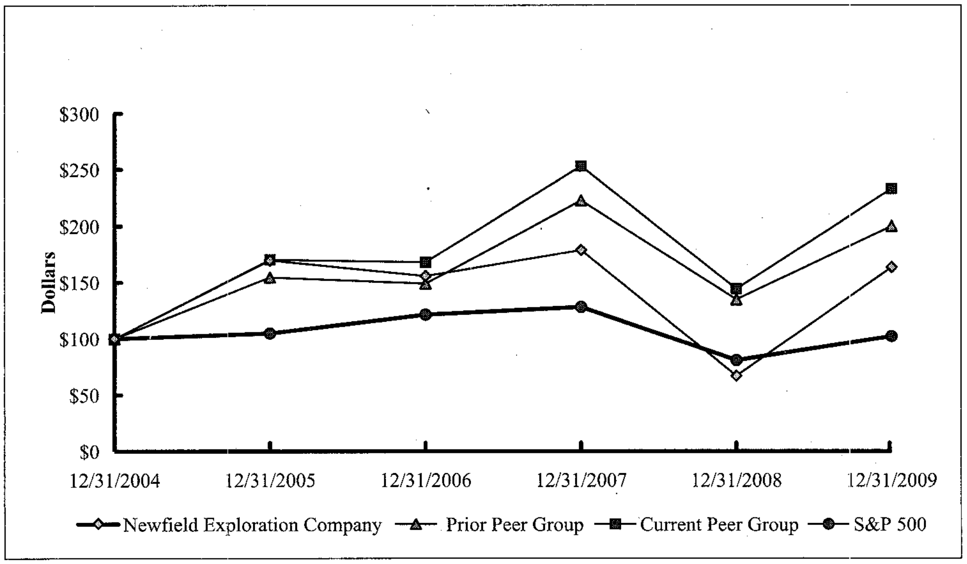
Stockholder Return Performance Presentation

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, our "prior peer group" and our "current peer group" on December 31, 2004 at the closing price on such date;
- investment in each of our peer groups 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.

Prior Peer Group. Prior to 2009, our peer group consisted of Anadarko Petroleum Corporation, Apache Corporation, Bill Barrett Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, EOG Resources, Inc., Forest Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc., Pioneer Natural Resources Company, Range Resources Corporation, St. Mary Land & Exploration Company, Stone Energy Corporation, Swift Energy Company and XTO Energy Inc.

Current Peer Group. As part of its review of compensation during 2009, management and its compensation consultant reviewed the companies included in our peer group based on a variety of factors, including revenues, market capitalization, asset size, geographic location of assets and headquarters, culture and performance. As a result of this review, management adopted the current peer group. Our current peer group consists of Cabot Oil & Gas Corporation, Cimarex Energy Company, Denbury Resources Inc., EXCO Resources, Inc., Forest Oil Corporation, Noble Energy, Inc., Petrohawk Energy Corporation, Pioneer Natural Resources Company, Plains Exploration & Production Company, Range Resources Corporation, SandRidge Energy, Inc., Southwestern Energy Company and Ultra Petroleum Corp.



Total Return Analysis	12/31/2004	12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009
Newfield Exploration Company	$100.00	$169.57	$155.60	$178.48	$ 66.88	$163.31
Prior Peer Group	$100.00	$154.45	$148.83	$222.27	$134.73	$199.77
Current Peer Group	$100.00	$170.09	$167.90	$252.64	$144.09	$232.61
S&P 500	$100.00	$104.89	$121.46	$128.13	$ 80.73	$102.08

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* — Proved and Probable Reserves" and Item 7, *"Management's Discussion and Analysis of Financial Condition and Results of Operations,"* of this report.

	Year Ended December 31,				
	2009(1)	2008	2007	2006	2005
	(In millions, except per share data)				
Income Statement Data:					
Oil and gas revenues	$ 1,338	$ 2,225	$1,783	$ 1,673	$ 1,762
Income (loss) from continuing operations	(542)	(373)	172	610	342
Net income (loss)	(542)	(373)	450	591	348
Earnings (loss) per share:					
Basic —					
Income (loss) from continuing operations	(4.18)	(2.88)	1.35	4.82	2.73
Net income (loss)	(4.18)	(2.88)	3.52	4.67	2.78
Diluted —					
Income (loss) from continuing operations	(4.18)	(2.88)	1.32	4.73	2.68
Net income (loss)	(4.18)	(2.88)	3.44	4.58	2.73
Weighted average number of shares outstanding for basic earnings per share	130	129	128	127	125
Weighted average number of shares outstanding for diluted earnings per share	130	129	131	129	128
Cash Flow Data:					
Net cash provided by continuing operating activities	$ 1,578	$ 854	$1,166	$ 1,392	$ 1,119
Net cash used in continuing investing activities	(1,356)	(2,253)	(865)	(1,552)	(1,015)
Net cash provided by (used in) continuing financing activities	(168)	1,173	(117)	174	(124)
Balance Sheet Data (at end of period):					
Total assets	$ 6,254	$ 7,305	$6,986	$ 6,635	$ 5,081
Long-term debt	2,037	2,213	1,050	1,048	870
Proved Reserves Data (at end of period):					
Oil and condensate (MMBbls)	169	140	114	114	102
Gas (Bcf)	2,605	2,110	1,810	1,586	1,391
Total proved reserves (Bcfe)	3,616	2,950	2,496	2,272	2,001
Present value of estimated future after-tax net cash flows	$ 2,864	$ 2,929	$4,531	$ 3,447	$ 5,053

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

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

Overview

We are an independent oil and gas company engaged in the exploration, development and acquisition of oil and gas properties. Our domestic areas of operation include the Anadarko and Arkoma Basins of the Mid-Continent, the Rocky Mountains, onshore Texas and the Gulf of Mexico. Internationally, we are active in Malaysia and China.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and gas reserves. We use the full cost method of accounting for our oil and gas activities.

Oil and Gas Prices. Prices for oil and gas fluctuate widely. Oil and gas prices affect:

- the amount of cash flow available for capital expenditures;
- our ability to borrow and raise additional capital;
- the quantity of oil and gas that we can economically produce; and
- the accounting for our oil and gas activities including among other items, the determination of ceiling test writedowns.

Any extended decline in oil and gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital. Please see the discussion under *"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"* in Item 1A of this report and "— Liquidity and Capital Resources" below.

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production. 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.

Reserve Replacement. To maintain and grow our production and cash flow, we must continue to develop existing reserves and locate or acquire new oil and gas reserves to replace those reserves being produced. Please see "— Proved Reserves" below and "Supplementary Financial Information — Supplementary Oil and Gas Disclosures — Estimated Net Quantities of Proved Oil and Gas Reserves" in Item 8 of this report for the change in our total net proved reserves during the three-year period ended December 31, 2009. Substantial capital expenditures are required to find, develop and acquire oil and gas reserves. See Items 1 and 2, *"Business and Properties* — Proved and Probable Reserves — *Proved Reserves."*

Significant Estimates. We believe the most difficult, subjective or complex judgments and estimates we must make in connection with the preparation of our financial statements are:

- the quantity of our proved oil and gas reserves;
- the timing of future drilling, development and abandonment activities;
- the cost of these activities in the future;
- the fair value of the assets and liabilities of acquired companies;
- the fair value of our financial instruments including derivative positions; and
- the fair value of stock-based compensation.

Accounting for Hedging Activities. We do not designate price risk management activities as accounting hedges. Because hedges not designated for hedge accounting are accounted for on a mark-to-market basis, we have in the past experienced, and are likely in the future to experience, significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of December 31, 2009, we had net derivative assets of $281 million, of which 57% was measured based upon our valuation model (i.e. Black Scholes) and, as such, is classified as a Level 3 fair value measurement. We value these contracts using a model that considers various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments. We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties. Please see "— Critical Accounting Policies and Estimates — *Commodity Derivative Activities*" below and Note 5, "Derivative Financial Instruments," and Note 8, "Fair Value Measurements," to our consolidated financial statements in Item 8 of this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Results of Operations

Significant Events. We completed several significant transactions during 2008 and 2007 and recorded ceiling test writedowns under the full cost method of accounting at the end of 2008 and the first quarter of 2009, each of which affects the comparability of our results of operations and cash flows from period to period.

- As of December 31, 2008, we recorded a $1.8 billion ceiling test writedown. We recorded an additional $1.3 billion ceiling test writedown as of March 31, 2009.
- During the first six months of 2008, we entered into a series of transactions that had the effect of resetting all of our then outstanding crude oil hedges for 2009 and 2010. At the time of the reset, the mark-to-market value of these hedge contracts was a liability of $502 million and we paid an additional $56 million to purchase option contracts.
- In October 2007, we sold all of our interests in the U.K. North Sea for $511 million in cash. The historical results of operations of our U.K. North Sea operations are reflected in our financial statements as "discontinued operations." Except where noted, discussions in this report relate to continuing operations only.
- In August 2007, we sold our shallow water Gulf of Mexico assets for $1.1 billion in cash and the purchaser's assumption of liabilities associated with future abandonment of wells and platforms.
- In June 2007, we acquired Stone Energy Corporation's Rocky Mountain assets for $578 million in cash. Initially, we financed this acquisition through borrowings under our revolving credit agreement.

Please see Note 1, "Organization and Summary of Significant Accounting Policies — *Oil and Gas Properties*," Note 3, "Discontinued Operations," Note 4, "Oil and Gas Assets," and Note 5, "Derivative Financial Instruments," to our consolidated financial statements appearing in Item 8 of this report for a discussion regarding these events.

Revenues. All of our revenues are derived from the sale of our oil and gas production. The effects of the settlement of hedges designated for hedge accounting are included in revenue, but those not so designated have no effect on our reported revenues. None of our outstanding oil and gas hedging contracts as of December 31, 2009 are designated for hedge accounting and the settlement of all hedging contracts during 2009 and 2008 had no effect on reported revenues. However, revenues for 2007 include losses on the settlement of hedging contracts designated for hedge accounting of $7 million. Please see Note 5, "Derivative Financial Instruments," to our consolidated financial statements appearing 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, crude oil from our operations offshore Malaysia and China is produced into FPSOs and "lifted" and sold periodically as barge quantities are accumulated. Revenues are recorded when oil is lifted and sold, not when it is produced into the FPSO. As a result, the timing of liftings may impact period to period results.

Revenues of $1.3 billion for 2009 were 40% lower than 2008 revenues due to significantly lower average realized oil and gas prices partially offset by higher oil and gas production. Revenues of $2.2 billion for 2008 were 25% higher than 2007 revenues due to increased oil production and higher average realized prices for oil and gas partially offset by lower natural gas production.

	Year Ended December 31,		
	2009	**2008**	**2007**
Production[1]:			
Domestic:			
Natural gas (Bcf)	174.3	172.9	192.8
Oil and condensate (MBbls)	7,059	6,136	6,501
Total (Bcfe)	216.7	209.8	231.8
International:			
Natural gas (Bcf)	—	—	—
Oil and condensate (MBbls)	6,120	4,439	2,258
Total (Bcfe)	36.7	26.6	13.5
Total:			
Natural gas (Bcf)	174.3	172.9	192.8
Oil and condensate (MBbls)	13,179	10,575	8,759
Total (Bcfe)	253.4	236.4	245.3
Average Realized Prices[2]:			
Domestic:			
Natural gas (per Mcf)	$ 3.48	$ 7.65	$ 6.33
Oil and condensate (per Bbl)	51.19	86.84	61.32
Natural gas equivalent (per Mcfe)	4.47	8.85	6.98
International:			
Natural gas (per Mcf)	$ —	$ —	$ —
Oil and condensate (per Bbl)	59.72	82.03	69.21
Natural gas equivalent (per Mcfe)	9.95	13.67	11.53
Total:			
Natural gas (per Mcf)	$ 3.48	$ 7.65	$ 6.33
Oil and condensate (per Bbl)	55.15	84.82	63.35
Natural gas equivalent (per Mcfe)	5.28	9.39	7.23

(1) Represents volumes lifted and sold regardless of when produced.

(2) Average realized prices only include the effects of hedging contracts that are designated for hedge accounting. Prior to the fourth quarter of 2005, we applied hedge accounting to qualifying derivatives, and the last of our previously designated cash flow hedges settled during 2007. Had we included the effects of hedging contracts not designated for hedge accounting, our average realized price for total natural gas would have been $6.42, $7.12 and $7.62 per Mcf for 2009, 2008 and 2007, respectively. Our total oil and condensate average realized price would have been $81.23, $69.13 and $55.04 per Bbl for 2009, 2008 and 2007, respectively. Without the effects of any hedging contracts designated for hedge accounting, our 2007 average realized prices would have been $6.33 per Mcf for natural gas and $64.12 per Bbl for oil. All amounts for the year ended December 31, 2008 exclude the cash payments totaling $502 million to reset our 2009 and 2010 crude oil hedges.

Domestic Production. Our 2009 domestic oil and gas production, stated on a natural gas equivalent basis, increased 3% over 2008 production primarily due to increased production in our Mid-Continent division as a result of continued successful drilling efforts, partially offset by natural field declines and the voluntary curtailment of approximately 3 Bcfe of production during the second half of 2009 from our Mid-Continent division due to low natural gas prices.

Our 2008 domestic oil and gas production, stated on a natural gas equivalent basis, decreased 9% from 2007 production, primarily as a result of the sale of our shallow water Gulf of Mexico assets in August 2007. In addition, 2008 production was negatively impacted by the deferral of approximately 5 Bcfe of production related to the 2008 hurricanes in the Gulf of Mexico. Production from our June 2007 acquisition of Stone Energy Corporation's Rocky Mountain assets partially offset the impact of the hurricanes. Without the impact of the Gulf of Mexico asset sale and the Rocky Mountain asset acquisition, our total 2008 oil and gas production increased 20% over 2007 due to increased production in our Mid-Continent and Rocky Mountain divisions as a result of continued successful drilling efforts.

International Production. Our 2009 international oil production, stated on a natural gas equivalent basis, increased 38% over 2008 production primarily due to new field developments on PM 318 and PM 323 in Malaysia and the timing of liftings from our oil production in Malaysia. Our 2008 international oil production increased 97% over 2007 production primarily due to new field developments on PM 323 in Malaysia.

Operating Expenses. We believe the most informative way to analyze changes in our operating expenses from period to period is on a unit-of-production, or per Mcfe, basis. However, because of the previously noted significant events during 2009, 2008 and 2007 and the year over year increases in our international production, period to period comparisons are difficult. For example, offshore Gulf of Mexico properties typically have significantly higher lease operating costs relative to onshore properties and offshore production is not subject to production taxes but onshore production is subject to these taxes.

Year ended December 31, 2009 compared to December 31, 2008

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2009.

	Unit-of-Production			Total Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2009	2008		2009	2008	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 0.94	$ 1.00	(6)%	$ 203	$ 210	(4)%
Production and other taxes	0.15	0.29	(48)%	33	60	(46)%
Depreciation, depletion and amortization	2.14	2.84	(25)%	463	597	(22)%
General and administrative	0.64	0.65	(2)%	139	136	2%
Ceiling test and other impairments	6.20	8.54	(27)%	1,344	1,792	(25)%
Other	0.03	0.02	50%	8	4	124%
Total operating expenses	10.10	13.34	(24)%	2,190	2,799	(22)%
International:						
Lease operating	$ 1.53	$ 2.05	(25)%	$ 56	$ 55	3%
Production and other taxes	0.82	3.64	(77)%	30	97	(69)%
Depreciation, depletion and amortization	3.39	3.77	(10)%	124	100	24%
General and administrative	0.14	0.18	(22)%	5	5	12%
Ceiling test writedown	—	2.66	(100)%	—	71	(100)%
Total operating expenses	5.88	12.30	(52)%	215	328	(34)%
Total:						
Lease operating	$ 1.02	$ 1.12	(9)%	$ 259	$ 265	(2)%
Production and other taxes	0.25	0.66	(62)%	63	157	(60)%
Depreciation, depletion and amortization	2.32	2.95	(21)%	587	697	(16)%
General and administrative	0.57	0.60	(5)%	144	141	2%
Ceiling test and other impairments	5.30	7.88	(33)%	1,344	1,863	(28)%
Other	0.03	0.01	200%	8	4	124%
Total operating expenses	9.49	13.22	(28)%	2,405	3,127	(23)%

Domestic Operations. Our domestic operating expenses for 2009, stated on a Mcfe basis, decreased 24% over 2008 primarily due to the goodwill impairment charge recorded at December 31, 2008 and the magnitude of the full cost ceiling test writedowns recorded at December 31, 2008 and March 31, 2009. The components of the period to period change are as follows:

- Lease operating expense (LOE) decreased 6% per Mcfe due to lower overall operating and service costs and the 3% increase in production volumes period over period.
- Production and other taxes decreased 48% per Mcfe due to significantly lower realized commodity prices period over period. We received refunds of $24 million ($0.11 per Mcfe) during 2009 related to production tax exemptions on some of our onshore wells, whereas we received similar refunds of $35 million ($0.17 per Mcfe) during 2008.
- Our depreciation, depletion and amortization (DD&A) rate decreased 25% per Mcfe primarily as a result of the ceiling test writedowns recorded at December 31, 2008 and March 31, 2009.
- General and administrative (G&A) expense per Mcfe decreased 2% period over period while total G&A expense increased slightly. The decrease per Mcfe is primarily due to the 3% increase in production volumes period over period. The slight increase in total G&A is primarily due to increased employee-related expenses associated with our growing domestic workforce offset by a decrease in incentive compensation expense, which is calculated based on adjusted net income (as defined in our incentive

compensation plan). Adjusted net income for purposes of our incentive compensation plan excluded (a) unrealized gains and losses on commodity derivatives and (b) the impact from any full cost ceiling test writedowns. Additionally, we match the costs/benefits of the 2008 crude oil hedge unwind/reset with the period in which these barrels are produced for the purposes of determining adjusted net income. During 2009, we capitalized $58 million ($0.27 per Mcfe) of direct internal costs as compared to $49 million ($0.23 per Mcfe) in 2008.

- In 2009, we recorded a ceiling test writedown of $1.3 billion ($6.20 per Mcfe) due to significantly lower natural gas prices at March 31, 2009. In 2008, we recorded a ceiling test writedown of $1.7 billion ($8.25 per Mcfe) due to significantly lower oil and gas commodity prices at year-end 2008. In 2008, we also recorded a goodwill impairment charge of $62 million ($0.29 per Mcfe) due to the significant decline in oil and gas commodity prices and the decline in our market capitalization at that time.
- Other expenses for 2009 primarily includes long-term rig contract termination fees resulting from our decision to limit our 2009 capital expenditures to a level that we expected to be funded with cash flows from operations. Other expenses for 2008 includes the reversal of a portion of accrued business interruption insurance claims related to 2005 Hurricane Ivan which were determined during 2008 to be uncollectible.

International Operations. Our international operating expenses for 2009, stated on a Mcfe basis, decreased 52% over the same period of 2008 primarily due to the 2008 full cost ceiling test writedown in Malaysia and significantly higher production taxes during 2008 due to substantially higher oil prices. The components of the period to period change are as follows:

- LOE decreased 25% per Mcfe while total LOE increased slightly over 2008. The decrease in LOE per Mcfe is primarily due to increased production volumes associated with the new field developments on PM 318 and PM 323 in Malaysia and lower overall operating and service costs.
- Production and other taxes decreased significantly due to substantially lower realized oil prices during 2009.
- Total DD&A expense increased 24% primarily due to additional production volumes and the timing of liftings of these volumes associated with new field developments on PM 318 and PM 323 in Malaysia, partially offset by a decrease in the DD&A rate resulting from the 2008 Malaysia ceiling test writedown.
- G&A expense decreased 22% per Mcfe primarily due to the 38% increase in production volumes in 2009.
- In 2008, we recorded a ceiling test writedown of $71 million associated with our operations in Malaysia due to significantly lower oil prices at year-end 2008.

Year ended December 31, 2008 compared to December 31, 2007

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2008.

	Unit-of-Production			Total Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2008	2007		2008	2007	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 1.00	$1.21	(17)%	$ 210	$ 281	(25)%
Production and other taxes	0.29	0.31	(6)%	60	73	(17)%
Depreciation, depletion and amortization	2.84	2.78	2%	597	643	(7)%
General and administrative	0.65	0.65	—	136	150	(9)%
Ceiling test and other impairments	8.54	—	100%	1,792	—	100%
Other	0.02	—	100%	4	—	100%
Total operating expenses	13.34	4.95	169%	2,799	1,147	144%
International:						
Lease operating	$ 2.05	$2.41	(15)%	$ 55	$ 33	68%
Production and other taxes	3.64	2.10	73%	97	28	241%
Depreciation, depletion and amortization	3.77	2.85	32%	100	39	160%
General and administrative	0.18	0.35	(49)%	5	5	(2)%
Ceiling test writedown	2.66	—	100%	71	—	100%
Total operating expenses	12.30	7.71	60%	328	105	214%
Total:						
Lease operating	$ 1.12	$1.28	(13)%	$ 265	$ 314	(15)%
Production and other taxes	0.66	0.41	61%	157	101	56%
Depreciation, depletion and amortization	2.95	2.78	6%	697	682	2%
General and administrative	0.60	0.63	(5)%	141	155	(9)%
Ceiling test writedown	7.88	—	100%	1,863	—	100%
Other	0.01	—	100%	4	—	100%
Total operating expenses	13.22	5.10	159%	3,127	1,252	150%

Domestic Operations. Our domestic operating expenses for 2008, stated on a Mcfe basis, increased 169% over 2007 due primarily to a 2008 full cost ceiling test writedown and goodwill impairment charge. The components of the period to period change are as follows:

- LOE decreased 17% per Mcfe due to the sale of our shallow water Gulf of Mexico properties in August 2007, which had relatively high LOE per Mcfe. Our 2007 LOE was adversely impacted by repair expenditures of $52 million ($0.22 per Mcfe) related to the 2005 storms. Without the impact of the repair expenditures related to the 2005 storms, our 2007 LOE would have been $0.99 per Mcfe. The decrease in LOE was partially offset by higher operating costs in 2008 for all our operations.

- Production and other taxes decreased 6% per Mcfe due to refunds of $35 million ($0.17 per Mcfe) related to production tax exemptions on some of our onshore wells recorded during 2008 compared to refunds of $8 million ($0.04 per Mcfe) recorded during 2007. The benefit of the refunds was partially offset by increased commodity prices and increased production from our Mid-Continent and Rocky Mountain operations, which are subject to production taxes, and the sale of our Gulf of Mexico properties, which were not subject to production taxes.

- Our DD&A rate increased 2% per Mcfe while total DD&A expense decreased 7% period over period primarily due to the sale of our Gulf of Mexico properties in August 2007. The increase in the DD&A rate per Mcfe was due to higher cost reserve additions. This increase was partially offset by a decrease in accretion expense due to the significant reduction in our asset retirement obligation following the sale of our Gulf of Mexico properties.

- G&A expense per Mcfe remained flat period over period while total G&A expense decreased 9% over 2007. The decrease in total G&A expense was primarily due to a 2007 litigation settlement reserve associated with a statewide royalty owner class action lawsuit in Oklahoma which was partially offset by increased employee related expenses in 2008 due to our increased domestic workforce. During 2008, we capitalized $49 million ($0.23 per Mcfe) of direct internal costs as compared to $49 million ($0.21 per Mcfe) in 2007.

- In 2008, we recorded a ceiling test writedown of $1.7 billion ($8.25 per Mcfe) due to significantly lower oil and gas commodity prices at year-end 2008. We also recorded a goodwill impairment charge of $62 million ($0.29 per Mcfe) due to the significant decline in oil and gas commodity prices and the decline in our market capitalization at that time.

- Other expenses for 2008 includes the reversal of a portion of accrued business interruption insurance claims related to 2005 Hurricane Ivan which were determined during 2008 to be uncollectible.

International Operations. Our international operating expenses for 2008, stated on a Mcfe basis, increased 60% over the same period of 2007 primarily due to higher production taxes and a full cost ceiling test writedown in Malaysia. The components of the period to period change are as follows:

- LOE decreased 15% per Mcfe while total LOE increased 68% over 2007. The decrease on a per unit basis resulted from increased liftings in Malaysia. The increase in total LOE was primarily due to new field developments on PM 318 and PM 323 and higher operating costs in Malaysia.

- Production and other taxes increased significantly in 2008 due to an increase in the tax rate per unit for our oil lifted and sold in Malaysia as a result of substantially higher oil prices during 2008.

- The DD&A rate in 2008 increased as a result of higher cost reserve additions in Malaysia.

- G&A expense decreased 49% per Mcfe primarily due to increased production in Malaysia during 2008.

- In 2008, we recorded a ceiling test writedown of $71 million associated with our operations in Malaysia due to significantly lower oil prices at year-end 2008.

Interest Expense. The following table presents information about interest expense for each of the years in the three-year period ended December 31, 2009.

	Year Ended December 31,		
	2009	2008	2007
	(In millions)		
Gross interest expense:			
Credit arrangements	$ 8	$ 10	$ 14
Senior notes	12	13	23
Senior subordinated notes	102	87	59
Other	4	2	6
Total gross interest expense	126	112	102
Capitalized interest	(51)	(60)	(47)
Net interest expense	$ 75	$ 52	$ 55

The increase in gross interest expense in 2009 as compared to 2008, and 2008 as compared to 2007, resulted primarily from the May 2008 issuance of $600 million principal amount of our 7⅛% Senior

Subordinated Notes due 2018. In October 2007, we repaid $125 million principal amount of our 7.45% Senior Notes.

We capitalize interest with respect to our unproved properties. Capitalized interest during 2009 decreased as compared to 2008 due to a reduction in our unproved property base resulting from the evaluation of such leasehold acreage. Interest capitalized during 2008 increased over 2007 due to an increase in our unproved property base primarily as a result of the Rocky Mountain asset acquisition in June 2007.

Commodity Derivative Income (Expense). The significant fluctuation in commodity derivative income (expense) from year to year is due to the extreme volatility of oil and gas prices and changes in our outstanding hedging contracts during these years.

Taxes. The effective tax rates for the years ended December 31, 2009, 2008 and 2007 were 39%, 30% and 41%, respectively. Our effective tax rate was different than the federal statutory tax rate for all three years primarily 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 for 2009 increased because we released the valuation allowance related to the tax benefit associated with the Malaysia ceiling test writedown recorded in the fourth quarter of 2008. Our effective tax rate for 2008 decreased from 2007 because during 2008 we were not able to recognize the full tax benefit associated with the $71 million ceiling test writedown in Malaysia and the $62 million goodwill impairment charge did not generate a tax benefit.

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

Liquidity and Capital Resources

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

We establish a capital budget at the beginning of each calendar year. Our 2010 capital budget is $1.6 billion and focuses on projects we believe will generate and lay the foundation for production growth. Our 2010 capital budget (excluding acquisitions) is guided by our anticipated 2010 cash flows.

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

On January 25, 2010, we sold $700 million of 6⅞% Senior Subordinated Notes due 2020 and received net proceeds of $686 million. These notes were issued at 99.109% of par to yield 7%. We used $294 million of the net proceeds to repay all of our then outstanding borrowings under our credit facility, $215 million to fund the acquisition of assets from TXCO Resources Inc. and we tendered for approximately $143 million of our outstanding 7⅝% Senior Notes due 2011.

We continue to hold auction rate securities with a fair value of $40 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 nor 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 8, "Fair Value Measurements," to our consolidated financial statements for more information regarding the auction rate securities.

Credit Arrangements. We have a revolving credit facility that matures in June 2012 and provides for loan commitments of $1.25 billion from a syndicate of more than 15 financial institutions, led by JPMorgan Chase Bank as agent. As of December 31, 2009, the largest commitment was 16% of total commitments. However, the amount that we can borrow under the facility could be limited by changing expectations of future oil and gas prices because the maximum amount that we may borrow under the facility is determined by our lenders annually each May (and may be adjusted at the option of our lenders in the case of certain acquisitions or divestitures) using a process that takes into account the value of our estimated reserves and hedge position and the lenders' commodity price assumptions.

In the future, total commitments under the facility could be increased to a maximum of $1.65 billion if the existing lenders increase their individual loan commitments or new financial institutions are added to the facility. We do not believe we could access such additional capacity in the current credit market. In addition, subject to compliance with covenants in our credit facility that restrict our ability to incur additional debt, we also have a total of $120 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions. For a more detailed description of the terms of our credit arrangements, please see Note 9, "Debt ," to our consolidated financial statements appearing in Item 8 of this report.

At February 22, 2010, we had $1 million of undrawn letters of credit and outstanding borrowings of $75 million under our $1.25 billion credit facility. Our available borrowing capacity under our credit arrangements was approximately $1.3 billion as of February 22, 2010.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements and changes in the fair value of our outstanding commodity derivative instruments. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. Although we anticipate that our 2010 capital spending (excluding acquisitions) will correspond with our anticipated 2010 cash flows, we may borrow and repay funds under our credit arrangements throughout the year since the timing of expenditures and the receipt of cash flows from operations do not necessarily match.

At December 31, 2009, we had positive working capital of $20 million. The decrease in our working capital balance as compared to December 31, 2008 is primarily due to a $396 million decrease in net derivative assets and their related deferred taxes resulting from the settlement of contracts during 2009, partially offset by the timing of receivable collections from purchasers, payments made by us to vendors and other operators, and the timing and amount of advances received from our joint operations.

At December 31, 2008, we had positive working capital of $121 million. During 2008, we used $271 million of cash and short-term investments on hand at the beginning of 2008 to fund a portion of our capital program and reclassified $75 million of our auction rate securities from short-term to long-term investments. In addition, at December 31, 2008, we had a net derivative asset of $663 million compared to a net derivative liability of $84 million at December 31, 2007. These working capital increases were partially offset by a change in our net current deferred tax position. Our net current deferred tax position was a liability of $226 million at December 31, 2008 compared to an asset of $35 million at December 31, 2007.

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

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

Our net cash flow from operations was $1.6 billion in 2009, an increase of 85% compared to net cash flow from operations of $854 million in 2008. This increase is primarily due to cash receipts related to derivative settlements of $883 million during 2009 compared to cash payments of $750 million during 2008. The cash payments in 2008 included $558 million to reset our 2009 and 2010 crude oil hedging contracts effectively settling the liability on our balance sheet at that time. Our 2009 net cash flows from operations were negatively impacted by lower average realized commodity prices during the year. Our working capital requirements during 2009 increased compared to 2008 as a result of the timing of drilling activities, receivable collections from purchasers, payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations.

Our net cash flow from operations was $854 million in 2008, a decrease of 26% compared to net cash flow from operations of $1.2 billion in 2007. This decrease is primarily due to the $558 million paid in 2008 to reset our 2009 and 2010 crude oil hedging contracts. Even though our 2008 production volumes were impacted by our 2007 property sales, the impact of this transaction on net cash flows from operations was somewhat offset by higher average realized commodity prices during 2008, increased production from our Mid-Continent and Rocky Mountain divisions and increased liftings in Malaysia. Our working capital requirements during 2008 decreased compared to 2007 as a result of the timing of drilling activities, receivable collections from purchasers, payments made by us to vendors and other operators, and the timing and amount of advances received from our joint operations.

Cash Flows from Investing Activities. Net cash used in investing activities for 2009 was $1.4 billion compared to $2.3 billion for 2008.

During 2009, we:

- spent $1.4 billion (including $9 million for acquisitions of oil and gas properties);
- received proceeds of $33 million from sales of oil and gas properties; and
- redeemed investments of $20 million.

During 2008, we:

- spent $2.3 billion (including $223 million for acquisitions of oil and gas properties); and
- purchased investments of $22 million and redeemed investments of $70 million.

Capital Expenditures. Our capital spending of $1.4 billion for 2009 decreased 38% from our $2.3 billion of capital spending during 2008. These amounts exclude recorded asset retirement obligations of $19 million in 2009 and $15 million in 2008. Of the $1.4 billion spent in 2009, we invested $937 million in domestic exploitation and development, $181 million in domestic exploration (exclusive of exploitation and leasehold activity), $147 million in acquisitions of proved and unproved property (leasehold) and domestic leasing activity and $148 million outside the United States.

Our capital spending of $2.3 billion for 2008 decreased 13% from our $2.6 billion of capital spending during 2007. These amounts exclude recorded asset retirement obligations of $15 million in 2008 and $21 million in 2007. Of the $2.3 billion spent in 2008, we invested $1.3 billion in domestic exploitation and development, $352 million in domestic exploration (exclusive of exploitation and leasehold activity), $363 million in acquisitions (includes the acquisition of properties in South Texas) and domestic leasing activity and $225 million outside the United States.

We have budgeted $1.6 billion for capital spending in 2010, including $124 million of estimated capitalized interest and overhead. Approximately 40% of the $1.6 billion is initially allocated to the Mid-Continent, 23% to the Rocky Mountains, 14% to the Gulf of Mexico, 10% to onshore Texas, and 13% to international projects. See Items 1 and 2, "*Business and Properties* — Our Properties and Plans for 2010." The 2010 capital budget is based on our expectation that we will live within anticipated cash flow from operations (excluding acquisitions). Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable.

Cash Flows from Financing Activities. Net cash used in financing activities for 2009 was $168 million compared to $1.2 billion of net cash provided by financing activities for 2008.

During 2009, we:

- borrowed $1.0 billion and repaid $1.2 billion under our credit arrangements; and
- received proceeds of $9 million from the issuance of shares of our common stock upon the exercise of stock options.

During 2008, we:

- borrowed $2.6 billion and repaid $2.0 billion under our credit arrangements;
- issued $600 million aggregate principal amount of our 7⅛% Senior Subordinated Notes due 2018 and paid $8 million in associated debt issue costs; and
- received proceeds of $20 million from the issuance of shares of our common stock upon the exercise of stock options.

Proved Reserves

To maintain and grow our production and cash flow, we must continue to develop existing proved reserves and locate or acquire new oil and gas reserves to replace those reserves being produced. The following is a discussion of proved reserves, reserve additions and revisions and future net cash flows from proved reserves.

	2009	2008	2007
		(Bcfe)	
Proved Reserves:			
Beginning of year	2,950	2,496	2,272
Reserve additions	1,342	758	881
Reserve revisions	(384)	(67)	(12)
Sales	(35)	(2)	(396)
Production	(257)	(235)	(249)
End of year	3,616	2,950	2,496
Proved Developed Reserves:			
Beginning of year	1,827	1,566	1,484
End of year	1,908	1,827	1,566

Our proved natural gas reserves at year-end 2009 were 2.6 Tcf compared to 2.1 Tcf at year-end 2008 and 1.8 Tcf at year-end 2007. Our proved crude oil and condensate reserves at year-end 2009 were 169 million barrels compared to 140 million barrels at year-end 2008 and 114 million barrels at year-end 2007. Natural gas comprised about 72%, 72% and 73% of our proved reserves at year-end 2009, 2008 and 2007, respectively.

Reserve Additions and Revisions. During 2009, we added 958 Bcfe net proved reserves as a result of additions (extensions, discoveries, improved recovery and purchases of reserves in place) and revisions, as described below. Of this amount, 693 Bcfe of proved undeveloped reserves primarily associated with our Woodford Shale and Monument Butte fields was the result of the changes in SEC reserves reporting rules expanding proved undeveloped reserves beyond one offset to a proved developed location. We expect the majority of future reserve additions to be associated with infill drilling, extensions of current fields and new discoveries, as well as improved recovery operations and purchases of proved properties. The success of these operations will directly impact reserve additions or revisions in the future.

Additions. We added 1,342 Bcfe proved reserves during 2009, approximately 521 Bcfe of which were the result of successful development drilling in our Mid-Continent and Rocky Mountain business units. During 2008, we added 758 Bcfe of proved reserves, approximately 599 Bcfe of which were as a result of successful drilling efforts in the Mid-Continent and Rocky Mountains. During 2007, we added 881 Bcfe of proved reserves. Of this amount, 519 Bcfe was related to successful development drilling in our Mid-Continent and

Onshore Gulf Coast business units and approximately 198 Bcfe was related to our purchase of reserves in place primarily associated with the acquisition of Stone Energy's Rocky Mountain assets in June 2007.

Revisions. Total revisions in 2009 were a negative 384 Bcfe, or 13% of the beginning of year reserve base. The revisions included a negative price revision of 259 Bcfe primarily related to our onshore natural gas plays, such as the Woodford Shale, and were primarily proven undeveloped reserves. The remaining 125 Bcfe of revisions in 2009 were negative performance revisions and were principally proved developed producing reserve revisions. Total revisions for 2008 were a negative 67 Bcfe and were primarily price-related domestic revisions associated with the decrease in both oil and gas prices from 2007 to 2008. Total revisions for 2007 were a negative 12 Bcfe and were primarily performance revisions associated with our Onshore Gulf Coast properties.

Sales. During 2009, we sold approximately 35 Bcfe of reserves associated with our domestic operations. In 2008, sales of reserves were negligible. Substantially all the 396 Bcfe of sales of oil and gas reserves during 2007 were related to our shallow water Gulf of Mexico assets and our coal bed methane assets in the Cherokee Basin of Oklahoma.

Future Net Cash Flows. At December 31, 2009, the present value (discounted at 10%) of estimated future net cash flows from our proved reserves was $2.9 billion (stated in accordance with the regulations of the SEC and the Financial Accounting Standards Board ("FASB")). This present value was calculated based on the unweighted average first-day-of-the-month oil and gas prices for the prior twelve months held flat for the life of the reserves. This amount is unchanged from the $2.9 billion at December 31, 2008 despite lower natural gas prices utilized to calculate 2009 proved reserves. Reserve quantity additions as a result of our drilling success during 2009 coupled with the additional reserve quantities recognized as a result of the SEC's new reserves rules offset the impact of the lower natural gas prices utilized to calculate 2009 proved reserves. The decrease of $1.6 billion, or 35%, in 2008 compared to 2007 is primarily due to lower commodity prices at year-end 2008. See *"Supplementary Financial Information* — Supplementary Oil and Gas Disclosures — Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves" under Item 8 of this report.

The present value of future net cash flows does not purport to be an estimate of the fair market value of our proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money to the evaluating party and the perceived risks inherent in producing oil and gas.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of December 31, 2009.

	Total	Less than 1 Year	2-3 Years	4-5 Years	More than 5 Years
			(In millions)		
Debt:					
Revolving credit facility	$ 384	$ —	$384	$ —	$ —
7⅝% Senior Notes due 2011	175	—	175	—	—
6⅝% Senior Subordinated Notes due 2014	325	—	—	325	—
6⅝% Senior Subordinated Notes due 2016	550	—	—	—	550
7⅛% Senior Subordinated Notes due 2018	600	—	—	—	600
Total debt	2,034	—	559	325	1,150
Other obligations:					
Interest payments(1)	738	118	215	201	204
Net derivative liabilities (assets)	(281)	(267)	(14)	—	—
Asset retirement obligations	92	10	13	9	60
Operating leases	127	63	20	18	26
Deferred acquisition payments	2	2	—	—	—
Firm transportation	233	31	59	58	85
Oil and gas activities(2)	508	—	—	—	—
Total other obligations	1,419	(43)	293	286	375
Total contractual obligations	$3,453	$ (43)	$852	$611	$1,525

(1) Interest associated with our revolving credit facility was calculated using a weighted average interest rate of 1.125% at December 31, 2009 and is included through the maturity of the facility.

(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 cash commitments. At December 31, 2009, these work-related commitments totaled $508 million and were comprised of $380 million in our domestic business and $128 million internationally. Our domestic obligation relates to a 10-year firm transportation agreement for our Mid-Continent production. This obligation is subject to the completion of construction, which is expected during the second quarter of 2010, and upon required regulatory approvals. Actual amounts by maturity are not included because their timing cannot be accurately predicted.

As of December 31, 2009, we have delivery commitments through 2011 to deliver to third party purchasers approximately 100,000 MMBtu of our daily production, principally from our Mid-Continent division. Given the size of our proved natural gas reserves and production capacity in our Mid-Continent division, we currently believe that we have sufficient reserves and production to fulfill these delivery commitments. See Items 1 and 2, *"Business and Properties"* for a description of our Mid-Continent production and proved reserves.

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

Senior Notes

In February 2001, we issued $175 million aggregate principal amount of our 7⅝% Senior Notes due 2011.

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

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

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

On February 19, 2010, we announced that we had accepted for purchase and payment approximately $143 million of our $175 million aggregate principal amount of 7⅝% Senior Notes due 2011 pursuant to a tender offer and consent solicitation that we began January 20, 2010. We funded the tender offer with a portion of the proceeds from our January 25, 2010 issuance of $700 million aggregate principal amount of our 6⅞% Senior Subordinated Notes due 2020. See Note 19, "Subsequent Events," to our consolidated financial statements.

Senior Subordinated Notes

In August 2004, we issued $325 million aggregate principal amount of our 6⅝% Senior Subordinated Notes due 2014. The net proceeds from the offering were $323 million.

In April 2006, we issued $550 million aggregate principal amount of our 6⅝% Senior Subordinated Notes due 2016. The net proceeds from the offering were $545 million.

In May 2008, we issued $600 million aggregate principal amount of our 7⅛% Senior Subordinated Notes due 2018. We received net proceeds from the offering of $592 million.

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

We may redeem some or all of our 6⅝% notes due 2014 at any time on or after September 1, 2009 and some or all of our 6⅝% notes due 2016 at any time on or after April 15, 2011, in each case, at a redemption price stated in the applicable indenture governing the notes. We also may redeem all but not part of our 6⅝% notes due 2016 prior to April 15, 2011, at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption.

We may redeem some or all of our 7⅛% notes at any time on or after May 15, 2013 at a redemption price stated in the indenture governing the notes. Prior to May 15, 2013, we may redeem all, but not part, of our 7⅛% notes at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. In addition, before May 15, 2011, we may redeem up to 35% of the original principal amount of our 7⅛% notes with the net cash proceeds of certain sales of our common stock at 107.125% of the principal amount, plus accrued and unpaid interest to the date of redemption.

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

- incur additional debt;
- make restricted payments;
- pay dividends on or redeem our capital stock;
- make certain investments;
- create liens;

- engage in transactions with affiliates; and

- engage in mergers, consolidations and sales and other dispositions of assets.

On January 25, 2010, we sold $700 million of 6⅞% Senior Subordinated Notes due 2020 and received net proceeds of $686 million. These notes were issued at 99.109% of par to yield 7%. We used $294 million of the net proceeds to repay all of our then outstanding borrowings under our credit facility, $215 million to fund the acquisition of assets from TXCO Resources Inc. and we tendered for approximately $143 million of our outstanding 7⅝% Senior Notes due 2011.

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

Oil and Gas Hedging

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months to reduce our exposure to fluctuations in oil and gas prices. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive drilling programs. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions. As of February 22, 2010, approximately 64% of our estimated 2010 production was subject to derivative contracts (including basis contracts). In 2009, 85% of our production was subject to derivative contracts, compared to 72% in 2008 and 87% in 2007.

While the use of these hedging arrangements limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty and we have netting arrangements with all of our counterparties that provide for offsetting payables and receivables from separate hedging arrangements with that counterparty. At December 31, 2009, Barclays Capital, JPMorgan Chase Bank, N.A., Credit Suisse Energy LLC, Credit Agricole Corporate & Investment Bank London Branch, J Aron & Company and Societe Generale were the counterparties with respect to 82% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

A significant number of the counterparties to our hedging arrangements also are lenders under our credit facility. Our credit facility, 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. None of our derivative contracts contain collateral posting requirements; however, two of our derivative contracts contain a provision that would permit the counterparty, in certain circumstances, to request adequate assurance of our performance under the contract.

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

The price that we receive for natural gas production from the Gulf of Mexico and onshore Gulf Coast, after basis differentials, transportation and handling charges, typically averages $0.25-$0.50 per MMBtu less than the Henry Hub Index. Realized natural gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average 85-90% of the Henry Hub Index. In the Rocky Mountains, we hedged basis associated with approximately 15 Bcf of our natural gas production from January 2010 through December 2012 to lock in the differential at a weighted average of $0.95 per MMBtu less than the Henry Hub Index. In total, this hedge and the 8,000 MMBtus per day we have sold on a fixed physical basis for the same period results in an average basis hedge of $0.95 per MMBtu. In the Mid-Continent, we hedged basis associated with approximately 12 Bcf of our anticipated Stiles/Britt Ranch natural gas production from January 2010 through August 2011. In total, this hedge and the 30,000 MMBtus per day we have sold on a fixed physical basis for the same period results in an average basis hedge of $0.52 per MMBtu. We have also hedged basis associated with approximately 23 Bcf of our natural gas production from this area for the period September 2011 through December 2012 at an average of $0.55 per MMBtu.

The price we receive for our Gulf Coast oil production typically averages about 90-95% of the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains is currently averaging about $12-$14 per barrel below the WTI price. Oil production from our Mid-Continent properties typically averages 80-85% of the WTI price. Oil sales from our operations in Malaysia typically sell at a slight discount to Tapis, or about 90-95% of WTI. Oil sales from our operations in China typically sell at $4-$6 per barrel less than the WTI price.

Please see the discussion and tables in Note 5, "Derivative Financial Instruments," to our consolidated financial statements for a description of the accounting applicable to our hedging program, a listing of open contracts as of December 31, 2009 and the estimated fair market value of those contracts as of that date. Between January 1, 2010 and February 22, 2010, we did not enter into additional derivative contracts.

Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

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

Policies," to our consolidated financial statements for a discussion of additional accounting policies and estimates we make.

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

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

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

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

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

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

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

Depreciation, Depletion and Amortization. Estimated proved oil and gas reserves are a significant component of our calculation of DD&A expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test writedown. To change our domestic DD&A rate by $0.10 per Mcfe for the year ended December 31, 2009 would have required a change in the estimate of our domestic proved reserves of approximately 4%, or 140 Bcfe. To change our Malaysia DD&A rate by $0.10 per Mcfe for the year ended December 31, 2009 would have required a change in the estimate of our proved reserves in Malaysia of approximately 3%, or 5 Bcfe. Since production from our China operations is immaterial, any change in the DD&A rate as a result of changes in our proved reserves in China would not have materially affected our consolidated results of operations.

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

At December 31, 2009, the ceiling value of our oil and gas reserves was calculated based on the unweighted average first-day-of-the-month commodity prices for the prior twelve months of $3.87 per MMBtu for natural gas and $61.14 per barrel for oil, adjusted for market differentials. Based on 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. Holding all other factors constant, if the applicable unweighted average first-day-of-the-month commodity prices for the prior twelve months for oil or gas were to decline approximately 5% from prices used at December 31, 2009, it is possible we could experience a domestic full cost ceiling test writedown. Holding all other factors constant, it is possible that we could experience a ceiling test writedown in Malaysia and China if the applicable unweighted average first-day-of-the-month oil price declined approximately 15% and 25%, respectively, from prices used at December 31, 2009.

At March 31, 2009, prior to our adoption of the Final Rule and ASU 2010-03, the ceiling value of our reserves was calculated based upon quoted period-end market prices of $3.63 per MMBtu for natural gas and

$49.65 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties at March 31, 2009 exceeded the ceiling amount by approximately $1.3 billion ($854 million, after-tax), resulting in a ceiling test writedown.

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

Costs Withheld From Amortization. Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage and seismic data, wells currently 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, 2009, we had a total of approximately $1.2 billion of costs excluded from the amortization base of our respective full cost pools. The application of the full cost ceiling test at December 31, 2009 resulted in an excess of the cost center ceilings over the carrying value of our oil and gas properties for each full cost pool. Holding all other factors constant, inclusion of approximately 15% of our unevaluated property costs in our domestic amortization base would have resulted in a ceiling test writedown.

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, 2009 would have required a change in the estimate of our domestic future development and abandonment costs of approximately 10%, or $265 million. To change our Malaysia DD&A rate by $0.10 per Mcfe for the year ended December 31, 2009 would have required a change in the estimate of our future development and abandonment costs in Malaysia of approximately 8%, or $17 million. Since production from our China operations is immaterial, any change in the DD&A rate as a result of changes in the estimate of our future development and abandonment costs in China would not have materially affected our consolidated results of operations.

Allocation of Purchase Price in Business Combinations. As part of our growth strategy, we monitor and screen for potential acquisitions of oil and gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and gas reserves and unproved properties. To the extent the consideration paid exceeds the fair value of the net assets acquired, we are required to record the excess as an asset called goodwill. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain. The value allocated to recoverable oil and gas reserves and unproved properties is subject to the cost center ceiling as described under "*— Full Cost Ceiling Limitation*" above. The accounting for business combinations changed effective January 1, 2009 and established how a purchaser recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The standard also sets forth guidance related to the recognition, measurement and disclosure related to goodwill acquired in a business combination or gains associated with a bargain purchase transaction. The standard applies prospectively to business combinations for which the acquisition date is on or after December 31, 2008. We adopted the standard effective January 1, 2009.

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

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

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

Stock-Based Compensation. We apply a fair value-based method of accounting for stock-based compensation which requires recognition in the financial statements of the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. For equity-based compensation awards, compensation expense is based on the fair value on the date of grant or modification, and is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and a lattice-based model for our performance and market-based restricted stock. See Note 11, "Stock-Based Compensation," to our consolidated financial statements for a full discussion of our stock-based compensation.

New Accounting Requirements

In September 2006, the FASB defined fair value, established criteria to be considered when measuring fair value and expanded disclosures about fair value measurements. The guidance is effective for all recurring measures of financial assets and liabilities (e.g. derivatives and investment securities) for fiscal years beginning after November 15, 2007. We adopted the provisions for all recurring measures of financial assets and liabilities on January 1, 2008. In February 2008, the FASB issued additional authoritative guidance, which granted a one-year deferral of the effective date as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and asset retirement obligations). Beginning January 1, 2009, we applied the provisions to non-financial assets and liabilities. The adoption did not have a material impact on our financial position or results of operations.

In December 2007, the FASB established how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The standard also recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase and determines what information to disclose in the financial statements. The standard applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We adopted the standard effective January 1, 2009. The adoption of the standard did not impact our financial position or results of operations, but may have a material impact on our financial position or results of operations for businesses we acquire post-adoption.

In March 2008, the FASB issued guidance requiring enhanced disclosures about our derivative and hedging activities that is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted the disclosure requirements beginning January 1, 2009. Please see Note 5, "Derivative Financial Instruments — *Additional Disclosures about Derivative Instruments and Hedging Activities.*" The adoption did not have an impact on our financial position or results of operations.

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

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

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

On January 6, 2010, the FASB issued ASU 2010-03, which aligns the FASB's oil and gas reserve estimation and disclosure requirements with the requirements in the SEC's Final Rule.

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

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

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

Due to the extent of our domestic and international oil and gas activities and the limited time interval allowed for preparing our annual report on Form 10-K, it was not practical to prepare estimates of oil and gas reserves using end of period prices and to generate discounted cash flow models for estimates of proved reserves using both the previous rules and the new rules. Therefore, it was not practical to quantify the volumetric impact of the change in reserves rules and methodology or the impact, if any, on our full-cost ceiling test or depletion rate.

Regulation

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

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

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

Oil and Gas Prices

We generally hedge a substantial, but varying, portion of our anticipated oil and gas production for the next 12-24 months as part of our risk management program. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between NYMEX Henry Hub posted prices and those of our physical pricing points. We use hedging to reduce our exposure to fluctuations in oil and gas prices. 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 hedging limits the downside risk of adverse price movements, it also may limit future revenues from favorable price movements. 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. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. For a further discussion of our hedging activities, see information under the caption "Oil and Gas Hedging" in Item 7 of this report and the discussion and tables in Note 5, "Derivative Financial Instruments," to our consolidated financial statements appearing in Item 8 of this report.

Interest Rates

At December 31, 2009, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Bank revolving credit facility	$ —	$384
7⅝% Senior Notes due 2011[1]	125	50
6⅝% Senior Subordinated Notes due 2014	325	—
6⅝% Senior Subordinated Notes due 2016	550	—
7⅛% Senior Subordinated Notes due 2018	600	—
Total debt	$1,600	$434

(1) $50 million principal amount of our 7⅝% Senior Notes due 2011 is subject to an interest rate swap. The swap provides for us to pay variable and receive fixed interest payments, and is designated as a fair value hedge of a portion of our outstanding senior notes.

On January 25, 2010, we sold $700 million of 6⅞% Senior Subordinated Notes due 2020 and received net proceeds of $686 million. These notes were issued at 99.109% of par to yield 7%. We used $294 million of the net proceeds to repay all of our then outstanding borrowings under our credit facility, $215 million to fund the acquisition of assets from TXCO Resources Inc. and we tendered for approximately $143 million of our outstanding 7⅝% Senior Notes due 2011. As a result, substantially all of our debt is at fixed rates as of February 22, 2010.

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 flow, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at December 31, 2009.

Item 8. *Financial Statements and Supplementary Data*

NEWFIELD EXPLORATION COMPANY

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CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

Based on our evaluation under the framework in *Internal Control — Integrated Framework,* the management of our company concluded that our internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of our internal control over financial reporting as of December 31, 2009 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

Lee K. Boothby
President and Chief Executive Officer

Terry W. Rathert
Executive Vice President and Chief Financial Officer

Houston, Texas
February 26, 2010

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 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

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

PricewaterhouseCoopers LLP

Houston, Texas
February 26, 2010

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEET
(In millions, except share data)

	December 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 78	$ 24
Accounts receivable	339	375
Inventories	84	96
Derivative assets	269	663
Other current assets	123	48
Total current assets	893	1,206
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,223 and $1,303 were excluded from amortization at December 31, 2009 and 2008, respectively)	10,406	10,349
Less — accumulated depreciation, depletion and amortization	(5,159)	(4,591)
Total property and equipment, net	5,247	5,758
Derivative assets	19	247
Long-term investments	55	72
Deferred taxes	26	—
Other assets	14	22
Total assets	$ 6,254	$ 7,305
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 83	$ 103
Accrued liabilities	640	672
Advances from joint owners	51	73
Asset retirement obligation	10	11
Derivative liabilities	2	—
Deferred taxes	87	226
Total current liabilities	873	1,085
Other liabilities	55	22
Derivative liabilities	5	—
Long-term debt	2,037	2,213
Asset retirement obligation	82	70
Deferred taxes	434	658
Total long-term liabilities	2,613	2,963
Commitments and contingencies (Note 14)	—	—
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, 2009 and 2008; 134,493,670 and 133,985,751 shares issued at December 31, 2009 and 2008, respectively)	1	1
Additional paid-in capital	1,389	1,335
Treasury stock (at cost, 1,488,968 and 1,908,243 shares at December 31, 2009 and 2008, respectively)	(33)	(32)
Accumulated other comprehensive income (loss):		
Unrealized loss on investments	(11)	(13)
Unrealized gain on post-retirement benefits	—	2
Retained earnings	1,422	1,964
Total stockholders' equity	2,768	3,257
Total liabilities and stockholders' equity	$ 6,254	$ 7,305

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

NEWFIELD EXPLORATION COMPANY

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

	Year Ended December 31,		
	2009	2008	2007
Oil and gas revenues	$ 1,338	$2,225	$1,783
Operating expenses:			
Lease operating	259	265	314
Production and other taxes	63	157	101
Depreciation, depletion and amortization	587	697	682
General and administrative	144	141	155
Ceiling test and other impairments	1,344	1,863	—
Other	8	4	—
Total operating expenses	2,405	3,127	1,252
Income (loss) from operations	(1,067)	(902)	531
Other income (expense):			
Interest expense	(126)	(112)	(102)
Capitalized interest	51	60	47
Commodity derivative income (expense)	252	408	(188)
Other	5	11	6
Total other income (expense)	182	367	(237)
Income (loss) from continuing operations before income taxes	(885)	(535)	294
Income tax provision (benefit):			
Current	48	36	92
Deferred	(391)	(198)	30
Total income tax provision (benefit)	(343)	(162)	122
Income (loss) from continuing operations	(542)	(373)	172
Income from discontinued operations, net of tax	—	—	278
Net income (loss)	$ (542)	$ (373)	$ 450
Earnings per share:			
Basic —			
Income (loss) from continuing operations	$ (4.18)	$ (2.88)	$ 1.35
Income from discontinued operations	—	—	2.17
Net income (loss)	$ (4.18)	$ (2.88)	$ 3.52
Diluted —			
Income (loss) from continuing operations	$ (4.18)	$ (2.88)	$ 1.32
Income from discontinued operations	—	—	2.12
Net income (loss)	$ (4.18)	$ (2.88)	$ 3.44
Weighted average number of shares outstanding for basic earnings per share	130	129	128
Weighted average number of shares outstanding for diluted earnings per share	130	129	131

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

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In millions)

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
Balance, December 31, 2006	131.1	$ 1	(1.9)	$(30)	$1,198	$1,887	$ 6	$3,062
Issuances of common and restricted stock	1.4	—			32			32
Stock-based compensation	0.7	—			34			34
Treasury stock, at cost			—	(2)				(2)
Stock-based compensation excess tax benefit					14			14
Comprehensive income (loss):								
Net income						450		450
Foreign currency translation adjustment, net of tax of $7							(14)	(14)
Reclassification adjustments for settled hedging positions, net of tax of $2							(3)	(3)
Reclassification adjustments for discontinued cash flow hedges, net of tax of ($1)							2	2
Changes in fair value of outstanding hedging positions, net of tax of ($4)							6	6
Total comprehensive income								441
Balance, December 31, 2007	133.2	1	(1.9)	(32)	1,278	2,337	(3)	3,581
Issuances of common and restricted stock	0.9	—			20			20
Stock-based compensation	(0.1)	—			37			37
Comprehensive income (loss):								
Net loss						(373)		(373)
Unrealized loss on investments, net of tax of $6							(13)	(13)
Unrealized gain on post-retirement benefits, net of tax of ($3)							5	5
Total comprehensive loss								(381)
Balance, December 31, 2008	134.0	1	(1.9)	(32)	1,335	1,964	(11)	3,257
Issuances of common and restricted stock	0.5	—			9			9
Stock-based compensation					45			45
Treasury stock, at cost			0.4	(1)				(1)
Comprehensive income (loss):								
Net loss						(542)		(542)
Unrealized gain on investments, net of tax of ($1)							2	2
Realized loss on post-retirement benefits, net of tax of $1							(2)	(2)
Total comprehensive loss								(542)
Balance, December 31, 2009	134.5	$ 1	(1.5)	$(33)	$1,389	$1,422	$(11)	$2,768

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, 2009	2008	2007
Cash flows from operating activities:			
Net income (loss)	$ (542)	$ (373)	$ 450
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Income from discontinued operations, net of tax	—	—	(278)
Depreciation, depletion and amortization	587	697	682
Deferred tax provision (benefit)	(391)	(198)	30
Stock-based compensation	28	26	23
Commodity derivative (income) expense	(252)	(408)	188
Cash receipts (payments) on derivative settlements	883	(750)	180
Ceiling test and other impairments	1,344	1,863	—
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	36	(44)	(13)
Increase in inventories	(3)	(16)	(34)
Increase in commodity derivative assets	—	(65)	(2)
(Increase) decrease in other current assets	(75)	6	27
(Increase) decrease in other assets	4	(3)	(8)
Increase (decrease) in accounts payable and accrued liabilities	(23)	84	(22)
Increase (decrease) in advances from joint owners	(22)	29	(46)
Increase (decrease) in other liabilities	4	6	(11)
Net cash provided by continuing activities	1,578	854	1,166
Net cash used in discontinued activities	—	—	(12)
Net cash provided by operating activities	1,578	854	1,154
Cash flows from investing activities:			
Additions to oil and gas properties	(1,392)	(2,067)	(1,930)
Acquisitions of oil and gas properties	(9)	(223)	(658)
Proceeds from sales of oil and gas properties	33	9	1,344
Proceeds from sale of UK subsidiaries, net of cash on hand at sale date	—	—	491
Additions to furniture, fixtures and equipment	(8)	(20)	(13)
Purchases of investments	—	(22)	(271)
Redemption of investments	20	70	172
Net cash used in continuing activities	(1,356)	(2,253)	(865)
Net cash used in discontinued activities	—	—	(41)
Net cash used in investing activities	(1,356)	(2,253)	(906)
Cash flows from financing activities:			
Proceeds from borrowings under credit arrangements	1,040	2,579	2,909
Repayments of borrowings under credit arrangements	(1,216)	(2,018)	(2,909)
Net proceeds from issuance of senior subordinated notes	—	592	—
Repayment of senior notes	—	—	(125)
Payments to discontinued operations	—	—	(38)
Proceeds from issuances of common stock	9	20	32
Stock-based compensation excess tax benefit	—	—	14
Purchases of treasury stock, net	(1)	—	—
Net cash provided by (used in) continuing activities	(168)	1,173	(117)
Net cash provided by discontinued activities	—	—	38
Net cash provided by (used in) financing activities	(168)	1,173	(79)
Effect of exchange rate changes on cash and cash equivalents	—	—	1
Increase (decrease) in cash and cash equivalents	54	(226)	170
Cash and cash equivalents from continuing operations, beginning of period	24	250	52
Cash and cash equivalents from discontinued operations, beginning of period	—	—	28
Cash and cash equivalents, end of period	$ 78	$ 24	$ 250

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 oil and gas company engaged in the exploration, development and acquisition of oil and gas properties. Our domestic areas of operation include the Anadarko and Arkoma Basins of the Mid-Continent, the Rocky Mountains, onshore Texas and the Gulf of Mexico. Internationally, we are active in Malaysia and China.

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

In October 2007, we sold all of our interests in the U.K. North Sea for $511 million in cash and recorded a gain of $341 million. As a result, the historical results of our U.K. North Sea operations are reflected in our financial statements as "discontinued operations." See Note 3, "Discontinued Operations." Except where noted, discussions in these notes relate to our continuing operations only.

Dependence on Oil and Gas Prices

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

Use of Estimates

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

Reclassifications

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

Revenue Recognition

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

Foreign Currency

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

Cash and Cash Equivalents

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

Investments

Investments consist primarily of debt and equity securities as well as auction rate securities, substantially all 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 of stockholders' equity. 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 gains on our investment securities in 2009, 2008 and 2007 of $2 million, $4 million and $1 million, respectively.

Allowance for Doubtful Accounts

We routinely assess the recoverability of all material trade and other receivables to determine their collectibility. 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 45-60 days of production. We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated.

Inventories

Inventories primarily consist of tubular goods and well equipment held for use in our oil and gas operations and oil produced in our operations offshore Malaysia and China but not sold. Inventories are carried at the lower of cost or market. Crude oil from our operations offshore Malaysia and China is produced into FPSOs and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 289,000 barrels and 293,000 barrels of crude oil valued at cost of $11 million and $9 million at December 31, 2009 and 2008, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depreciation, depletion and amortization expense.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis. We capitalized $72 million, $69 million and $71 million of internal costs in 2009, 2008 and 2007, respectively. Interest expense related to unproved properties also is capitalized into oil and gas properties.

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

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using the newly effective oil and gas reserve estimation requirements (See *"New Accounting Requirements"* in this Note) which require use of the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus

- the lower of cost or estimated fair value of properties not included in the costs being amortized, if any; less

- related income tax effects.

For the years ended December 31, 2007 and 2008 and through September 30, 2009, the present value (10% per annum discount rate) of estimated future net revenues from proved reserves was calculated using the end of period quoted market prices for oil and gas.

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.

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

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil and gas prices decrease significantly or if we have substantial downward revisions in our estimated proved reserves. At December 31, 2009, the ceiling value of our reserves was calculated based upon the unweighted average first-day-of-the-month commodity prices for the prior twelve months of $3.87 per MMBtu for natural gas and $61.14 per barrel for oil, adjusted for market differentials. Using these prices, the cost center ceilings with respect to our properties in the U.S., Malaysia and China exceeded the net capitalized costs of the respective properties. As such, no ceiling test writedowns were required at December 31, 2009.

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

At December 31, 2008, the ceiling value of our reserves was calculated based upon quoted period-end market prices of $5.71 per MMBtu for natural gas and $44.61 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties exceeded the ceiling amount by approximately $1.7 billion ($1.1 billion, after-tax) at December 31, 2008. In addition, the unamortized net capitalized costs of our Malaysian properties exceeded the ceiling amount by approximately $71 million ($68 million, after-tax) at December 31, 2008. The ceiling with respect to our properties in China exceeded the net capitalized costs of the properties, requiring no writedown at December 31, 2008.

See Note 4, "Oil and Gas Assets," for a detailed discussion regarding our acquisition and sales transactions during 2009, 2008 and 2007.

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.

Goodwill

We assess the carrying amount of goodwill by testing the goodwill for impairment on an annual basis on December 31, or more frequently if an event occurs or circumstances change that have an adverse effect on the fair value of a reporting unit such that the fair value could be less than the book value of such unit. If the fair value of the reporting unit is less than its book value (including allocated goodwill), then goodwill is reduced to its implied fair value and the amount of the impairment is charged to earnings. The fair value of a reporting unit is based on our estimates of future net cash flows from proved reserves and from future exploration for and development of unproved reserves. During the fourth quarter of 2008, we recognized an impairment charge for all recorded goodwill in our domestic reporting unit in the amount of $62 million. The impairment charge resulted from the general decline in the economy and in the oil and gas industry and as a result, our market capitalization, as well as the significant decline in oil and gas commodity prices during the fourth quarter of 2008.

Accounting for Asset Retirement Obligations

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

The change in our ARO for the three years ended December 31, 2009 is set forth below (in millions):

Balance at January 1, 2007	$ 265
Accretion expense	9
Additions	15
Revisions	9
Settlements[1]	(236)
Balance at December 31, 2007	62
Accretion expense	4
Additions	12
Revisions	4
Settlements	(1)
Balance at December 31, 2008	$ 81
Accretion expense	6
Additions	11
Revisions	7
Settlements	(13)
Balance at December 31, 2009	$ 92
Less: Current portion of ARO at December 31, 2009	(10)
Total long-term ARO at December 31, 2009	$ 82

(1) $215 million relates to the sale of our shallow water Gulf of Mexico assets. See Note 4, "Oil and Gas Assets."

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.

During 2009, there was no change to our $1 million liability for uncertain tax positions. As of December 31, 2009, we had not accrued interest or penalties related to uncertain tax positions. The tax years 2005-2009 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject. During the fourth quarter of 2008, the Internal Revenue Service commenced a limited scope audit of our U.S. income tax return for the 2005 tax year. We anticipate that this audit should be completed by June 30, 2010.

Stock-Based Compensation

We use a fair value-based method of accounting for stock-based compensation. 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. See Note 11, "Stock-Based Compensation," for a full discussion of our stock-based compensation.

Concentration of Credit Risk

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

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

All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. The counterparties for all of our hedging transactions have an "investment grade" credit rating. We monitor on an ongoing basis the credit ratings of our hedging counterparties. Although we have entered into hedging contracts with multiple counterparties to mitigate our exposure to any individual counterparty, if any of our counterparties were to default on its obligations to us under the hedging contracts or seek bankruptcy protection, it could have a material adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future production being subject to commodity price changes. In addition, in poor economic environments and tight financial markets, the risk of a counterparty default is heightened and it is possible that fewer counterparties will participate in 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, 2009, Barclays Capital, JPMorgan Chase Bank, N.A., Credit Suisse Energy LLC, Credit Agricole Corporate & Investment Bank London Branch, J Aron & Company and Societe Generale were the counterparties with respect to 82% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

Major Customers

Sales of oil and gas production to Big West Oil LLC accounted for more than 10% of our consolidated revenues (before the effects of hedging) in 2009 and 2008 (16% in 2009, 13% in 2008), and sales to Superior Natural Gas Corporation accounted for 15% of our consolidated revenues (before the effects of hedging) in 2007. We believe that the loss of Superior Natural Gas Corporation would not have a material adverse effect on us because alternative purchasers are readily available. An extended loss of Big West Oil LLC, the largest purchaser of our Monument Butte field oil production, could have a material adverse effect on us because there are limited purchasers of the black wax crude oil 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. During the fourth quarter of 2008, Big West Oil LLC failed to pay for certain deliveries of crude oil and filed for bankruptcy protection. Although we continue to sell our black wax crude oil to that purchaser on a short-term basis that provides for more timely cash payments, we cannot guarantee that we will be able to continue to sell to this purchaser or that similar substitute arrangements could be made for sales of our black wax crude oil with other purchasers if desired.

Derivative Financial Instruments

We account for our derivative activities by applying authoritative accounting and reporting guidance which requires that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Substantially all of the derivative instruments that we utilize are to manage the price risk attributable to our expected oil and gas production. We have elected not to designate price risk management activities as accounting hedges under the accounting guidance, and, accordingly, account for them using the mark-to-market accounting method. Under this method, the changes in contract values are reported currently in earnings. We also utilize derivatives to manage our exposure to variable interest rates. See Note 5, "Derivative Financial Instruments — *Interest Rate Swap.*"

Prior to the fourth quarter of 2005, we applied hedge accounting to qualifying derivatives. Gains or losses on these collar and floor contracts were recorded as oil and gas revenues when the forecasted sale of production occurred. Any hedge ineffectiveness associated with contracts qualifying for and designated as cash flow hedges (which represented the amount by which the change in the fair value of the derivative differed from the change in the cash flows of the forecasted sale of production) was reported under the caption "Commodity derivative income (expense)" on our consolidated statement of income. The last of our previously designated cash flow hedges settled during 2007.

The related cash flow impact of all of our derivative activities are reflected as cash flows from operating activities. See Note 5, "Derivative Financial Instruments," for a more detailed discussion of our hedging 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.

New Accounting Requirements

In September 2006, the Financial Accounting Standards Board (FASB) defined fair value, established criteria to be considered when measuring fair value and expanded disclosures about fair value measurements. The guidance is effective for all recurring measures of financial assets and liabilities (e.g. derivatives and investment securities) for fiscal years beginning after November 15, 2007. We adopted the provisions for all recurring measures of financial assets and liabilities on January 1, 2008. In February 2008, the FASB issued additional authoritative guidance, which granted a one-year deferral of the effective date as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and asset retirement obligations). Beginning January 1, 2009, we applied the provisions to non-financial assets and liabilities. The adoption did not have a material impact on our financial position or results of operations.

In December 2007, the FASB established how a purchaser recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The standard also recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase and determines what information to disclose in the financial statements. The standard applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We adopted the standard effective January 1, 2009. The adoption of the standard did not impact our financial position or results of operations, but may have a material impact on our financial position or results of operations for businesses we acquire post-adoption.

In March 2008, the FASB issued guidance requiring enhanced disclosures about our derivative and hedging activities that is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted the disclosure requirements beginning January 1, 2009. Please see Note 5, "Derivative Financial Instruments — *Additional Disclosures about Derivative Instruments and Hedging Activities.*" The adoption did not have an impact on our financial position or results of operations.

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

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

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

On January 6, 2010, the FASB issued Accounting Standards Update No. 2010-03, *Oil and Gas Reserve Estimation and Disclosures* (ASU 2010-03), which aligns the FASB's oil and gas reserve estimation and disclosure requirements with the requirements in the SEC's Final Rule.

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

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

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

Due to the extent of our domestic and international oil and gas activities and the limited time interval allowed for preparing our annual report on Form 10-K, it was not practical to prepare estimates of oil and gas reserves using end of period prices and to generate discounted cash flow models for estimates of proved reserves using both the previous rules and the new rules. Therefore, it was not practical to quantify the volumetric impact of the change in reserves rules and methodology or the impact, if any, on our full-cost ceiling test or depletion rate.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted average number of shares of common stock (other than unvested restricted stock and restricted stock units) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted stock and restricted stock units (using the treasury stock method). Under the treasury stock method, the amount the employee must pay for exercising stock options, the amount of unrecognized compensation expense related to unvested stock-based compensation grants and the amount of excess tax benefits that would be recorded when the award becomes deductible are assumed to be used to repurchase shares. See Note 11, "Stock-Based Compensation."

The following is the calculation of basic and diluted weighted average shares outstanding and EPS for each of the years in the three-year period ended December 31, 2009:

	2009	2008	2007
	(In millions, except per share data)		
Income (numerator):			
Income (loss) from continuing operations	$ (542)	$ (373)	$ 172
Income from discontinued operations, net of tax	—	—	278
Net income (loss) — basic and diluted	$ (542)	$ (373)	$ 450
Weighted average shares (denominator):			
Weighted average shares — basic	130	129	128
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period(1)(2)	—	—	3
Weighted average shares — diluted	130	129	131
Earnings per share:			
Basic —			
Income (loss) from continuing operations	$(4.18)	$(2.88)	$1.35
Income from discontinued operations	—	—	2.17
Basic earnings (loss) per share	$(4.18)	$(2.88)	$3.52
Diluted —			
Income (loss) from continuing operations	$(4.18)	$(2.88)	$1.32
Income from discontinued operations	—	—	2.12
Diluted earnings (loss) per share	$(4.18)	$(2.88)	$3.44

(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 years ended December 31, 2009 and 2008 as their effect would have been anti-dilutive. Had we recognized net income for these periods, incremental shares attributable to the assumed exercise of outstanding stock options and the assumed vesting of unvested restricted stock and restricted stock units would have increased diluted weighted average shares outstanding by 2 million shares and 3 million shares for the years ended December 31, 2009 and 2008, respectively.

(2) The calculation of shares outstanding for diluted EPS for the year ended December 31, 2007 does not include the effect of 0.6 million of outstanding stock options and unvested restricted stock or restricted stock units because to do so would be antidilutive.

3. Discontinued Operations:

In October 2007, we sold all of our interests in the U.K. North Sea for $511 million in cash and recorded a gain of $341 million. As a result, the historical results of our U.K. North Sea operations are reflected in our financial statements as "discontinued operations."

The summarized financial results of the discontinued operations are as follows:

	Year Ended December 31, 2007
	(In millions)
Revenues	$ 8
Operating expenses(1)	(62)
Loss from operations	(54)
Commodity derivative expense	(5)
Gain on sale	341
Other expense(2)	(4)
Income before income taxes	278
Income tax provision(3)	—
Income from discontinued operations, net of tax	$278

(1) Operating expenses include a ceiling test writedown of $47 million recorded in the first quarter of 2007.

(2) Other expense primarily consists of U.K. withholding tax expense with respect to interest on intercompany loans.

(3) In October 2007, Newfield International Holdings (a Bahamian entity) sold the stock of the parent of our U.K. North Sea subsidiaries and realized a gain of $341 million. Because the Bahamas is a non-income taxing jurisdiction, no income tax provision was recorded in 2007.

4. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at:

	December 31, 2009	2008	2007
	(In millions)		
Oil and Gas Properties:			
Subject to amortization	$ 9,090	$ 8,961	$ 8,602
Not subject to amortization:			
Exploration in progress	243	207	250
Development in progress	92	71	30
Capitalized interest	131	129	103
Fee mineral interests	23	23	23
Other capital costs:			
Incurred in 2009	155	—	—
Incurred in 2008	180	328	—
Incurred in 2007	172	242	342
Incurred in 2006 and prior	227	303	441
Total not subject to amortization	1,223	1,303	1,189
Gross oil and gas properties	10,313	10,264	9,791
Accumulated depreciation, depletion and amortization	(5,108)	(4,550)	(3,868)
Net oil and gas properties	5,205	5,714	5,923
Other property and equipment	93	85	66
Accumulated depreciation and amortization	(51)	(41)	(31)
Net other property and equipment	42	44	35
Total property and equipment, net	$ 5,247	$ 5,758	$ 5,958

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

We believe that our evaluation activities related to substantially all of the properties associated with other capital costs not currently subject to amortization will be completed within four years except the Monument Butte field. Because of its size, evaluation of the field in its entirety will take significantly longer than four years. At December 31, 2009, 2008 and 2007, $176 million, $225 million and $264 million, respectively, of costs associated with the Monument Butte field were not subject to amortization.

Rocky Mountain Asset Acquisition

In June 2007, we acquired Stone Energy Corporation's Rocky Mountain assets for $578 million in cash. The unaudited pro forma results presented below have been prepared to give effect to the acquisition on our results of operations as if it had been consummated at the beginning of the period. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if this acquisition had been completed on such date or to project our results of operations for any future date or period.

	Year Ended December 31, 2007 (Unaudited) (In millions, except per share data)
Pro forma:	
Revenue	$1,831
Income from operations	545
Net income	465
Basic earnings per share	$ 3.65
Diluted earnings per share	$ 3.57

Gulf of Mexico Asset Sale

In August 2007, we sold our shallow water Gulf of Mexico assets for $1.1 billion in cash and the purchaser's assumption of liabilities associated with the future abandonment of wells and platforms. We retained most of our deepwater properties and interests in some exploration prospects on the shelf. The cash flows and results of operations for the assets included in the sale are included in our consolidated financial statements up to the date of sale.

Other Asset Acquisitions and Sales

During 2009 and 2008, we acquired various other oil and gas properties for approximately $9 million and $223 million, respectively, and sold various other oil and gas properties for approximately $33 million and $9 million, respectively. In September 2007, we sold our coal bed methane assets in the Cherokee Basin of northeastern Oklahoma for $128 million in cash.

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.

Other

In February 2010, we acquired assets from TXCO Resources Inc. See Note 19, "Subsequent Events." During the fourth quarter of 2009 we paid $20 million as an escrow deposit toward this transaction. In addition, we acquired certain claims for $20 million related to the bankruptcy proceedings associated with TXCO Resources Inc. Both of these amounts are included on our consolidated balance sheet under the caption "Other current assets."

5. Derivative Financial Instruments:

Commodity Derivative Instruments

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

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a floor contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price. We are not required to make any payment in connection with the settlement of a floor contract. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price, we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price. A three-way collar contract consists of a standard collar contract plus a put sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in us being entitled to a net payment equal to the difference between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional no cost collar while defraying the associated cost with the sale of the additional put. None of our derivative contracts contain collateral posting requirements; however, two of our derivative contracts contain a provision that would permit the counterparty, in certain circumstances, to request adequate assurance of our performance under the contract.

All of our derivative contracts are carried at their fair value on our consolidated balance sheet under the captions "Derivative assets" and "Derivative liabilities." Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors requires the use of an option-pricing model. See Note 8, "Fair Value Measurements." We recognize all unrealized and realized gains and losses related to these contracts on a mark-to-market basis in our consolidated statement of income under the caption "Commodity derivative income (expense)." Settlements of derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

During the first six months of 2008, we entered into a series of transactions that had the effect of resetting all of our then outstanding crude oil hedges for 2009 and 2010. At the time of the reset, the mark-to-market value of these hedge contracts was a liability of $502 million and we paid an additional $56 million to purchase option contracts.

At December 31, 2009, we had outstanding contracts with respect to our future production that are not designated for hedge accounting as set forth in the tables below.

Natural Gas

		NYMEX Contract Price per MMBtu								
					Collars				
			Additional Put		Floors		Ceilings		Estimated Fair Value Asset (Liability)
Period and Type of Contract	Volume in MMMBtus	Swaps (Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	(In millions)
January 2010 — March 2010									
Price swap contracts	31,800	$6.79	—	—	—	—	—	—	$ 36
Collar contracts	5,700	—	—	—	$8.50	$8.50	$10.00 - $11.00	$10.44	16
April 2010 — June 2010									
Price swap contracts	34,850	6.41	—	—	—	—	—	—	29
July 2010 — September 2010									
Price swap contracts	35,200	6.41	—	—	—	—	—	—	23
October 2010 — December 2010									
Price swap contracts	28,320	6.49	—	—	—	—	—	—	9
January 2011 — December 2011									
Price swap contracts	63,840	6.55	—	—	—	—	—	—	18
3-Way collar contracts	38,320	—	$4.50	$4.50	6.00	6.00	7.75 - 8.03	7.92	2
									$133

Oil

		NYMEX Contract Price Per Bbl							
					Collars				
			Additional Put		Floors		Ceilings		Estimated Fair Value Asset (Liability)
Period and Type of Contract	Volume in MBbls	Swaps (Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	(In millions)
January 2010 — March 2010									
Price swap contracts	90	$93.40	—	—	—	—	—	—	$ 1
Collar contracts	810	—	—	—	$125.50 - $130.50	$127.97	$170.00	$170.00	39
3-Way collar contracts	360	—	$50.00 - $60.00	$55.00	60.00 - 75.00	67.50	100.00 - 112.10	106.28	—
April 2010 — June 2010									
Price swap contracts	90	93.40	—	—	—	—	—	—	1
Collar contracts	819	—	—	—	125.50 - 130.50	127.97	170.00	170.00	38
3-Way collar contracts	364	—	50.00 - 60.00	55.00	60.00 - 75.00	67.50	100.00 - 112.10	106.28	—
July 2010 — September 2010									
Price swap contracts	90	93.40	—	—	—	—	—	—	1
Collar contracts	828	—	—	—	125.50 - 130.50	127.97	170.00	170.00	38
3-Way collar contracts	368	—	50.00 - 60.00	55.00	60.00 - 75.00	67.50	100.00 - 112.10	106.28	—
October 2010 — December 2010									
Price swap contracts	90	93.40	—	—	—	—	—	—	1
Collar contracts	828	—	—	—	125.50 - 130.50	127.97	170.00	170.00	38
3-Way collar contracts	368	—	50.00 - 60.00	55.00	60.00 - 75.00	67.50	100.00 - 112.10	106.28	—
January 2011 — December 2011									
3-Way collar contracts	1,460	—	60.00 - 65.00	62.50	75.00 - 80.00	77.50	118.50 - 121.50	119.94	2
									$159

Basis Contracts

At December 31, 2009, we had natural gas basis contracts that are not designated for hedge accounting to lock in the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points in the Rocky Mountains and Mid-Continent, as set forth in the table below.

	Rocky Mountains		Mid-Continent		Estimated Fair Value Asset (Liability)
	Volume in MMMBtus	Weighted Average Differential	Volume in MMMBtus	Weighted Average Differential	(In millions)
January 2010 — March 2010	1,380	$(0.99)	1,800	$(0.55)	$ (2)
April 2010 — June 2010	1,380	(0.99)	1,820	(0.55)	(1)
July 2010 — September 2010	1,380	(0.99)	1,840	(0.55)	(1)
October 2010 — December 2010	1,380	(0.99)	1,840	(0.55)	(1)
January 2011 — December 2011	5,280	(0.95)	10,350	(0.55)	(5)
January 2012 — December 2012	4,920	(0.91)	18,300	(0.55)	(4)
					$(14)

Interest Rate Swap

We entered into an interest rate swap agreement to take advantage of low interest rates and to obtain what we viewed as a more desirable proportion of variable and fixed rate debt. The agreement is designated as a fair value hedge of $50 million principal amount of our $175 million 7⅝% Senior Notes due 2011. The interest rate swap provides for us to pay variable and receive fixed interest payments. Changes in the fair value of derivatives designated as fair value hedges are recognized as offsets to the changes in the fair value of the exposure being hedged. As a result, the fair value of our interest rate swap is reflected as a derivative assets or liability on our consolidated balance sheet and changes in its fair value are recorded as an adjustment to the carrying value of the associated debt. Receipts and payments related to our interest rate swap are reflected in interest expense. The related cash flow impact is reflected as cash flows from operating activities in our consolidated statement of cash flows.

Additional Disclosures about Derivative Instruments and Hedging Activities

At December 31, 2009, we had derivative financial instruments recorded in our balance sheet as set forth below.

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability)
		(In millions)
Derivatives not designated as hedging instruments:		
Natural gas contracts	Derivative assets — current	$113
Oil contracts	Derivative assets — current	157
Basis contracts	Derivative assets — current	(3)
Natural gas contracts	Derivative assets — noncurrent	20
Oil contracts	Derivative assets — noncurrent	2
Basis contracts	Derivative assets — noncurrent	(4)
Basis contracts	Derivative liabilities — current	(2)
Basis contracts	Derivative liabilities — noncurrent	(5)
Total derivatives not designated as hedging instruments		278
Derivative designated as a fair value hedge:		
Interest rate swap	Derivative assets — current	2
Interest rate swap	Derivative assets — noncurrent	1
Total derivative designated as a hedging instrument		3
Net derivative assets		$281

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

Type of Contract	Location of Gain (Loss) Recognized in Income	Year Ended December 31, 2009
		(In millions)
Derivatives not designated as hedging instruments:		
Natural gas contracts	Commodity derivative income (expense)	$ 387
Oil contracts	Commodity derivative income (expense)	(100)
Basis contracts	Commodity derivative income (expense)	(35)
Derivative designated as a fair value hedge:		
Interest rate swap	Interest expense	1
Total		$ 253

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, 2009, Barclays Capital, JPMorgan Chase Bank, N.A., Credit Suisse Energy LLC, Credit Agricole Corporate & Investment Bank London Branch, J Aron & Company and Societe Generale were the counterparties with respect to 82% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

A significant number of the counterparties to our derivative instruments also are lenders under our credit facility. Our credit facility, 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.

6. Accounts Receivable:

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

	December 31, 2009	December 31, 2008
	(In millions)	
Revenue	$214	$157
Joint interest	114	197
Other	17	26
Allowance for doubtful accounts	(6)	(5)
Total accounts receivable	$339	$375

7. Accrued Liabilities:

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

	December 31, 2009	December 31, 2008
	(In millions)	
Revenue payable	$ 55	$ 75
Accrued capital costs	289	319
Accrued lease operating expenses	47	50
Employee incentive expense	61	73
Accrued interest on long-term debt	25	25
Taxes payable	101	69
Other	62	61
Total accrued liabilities	$640	$672

8. Fair Value Measurements:

Effective January 1, 2008, we adopted the authoritative guidance that applies to all financial assets and liabilities required to be measured and reported on a fair value basis. Beginning January 1, 2009, we also applied the guidance to non-financial assets and liabilities. 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 guidance requires disclosure that establishes a framework for measuring fair value, expands disclosure about fair value measurements 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 market place. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps, certain investments and interest rate swaps.

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

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

Fair Value of Investments and Derivative Instruments

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

	Fair Value Measurement Classification			
	Quoted Prices In Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(In millions)			
As of December 31, 2008:				
Investments available-for-sale:				
Equity securities	$ 6	$ —	$ —	$ 6
Auction rate securities	—	—	59	59
Oil and gas derivative swap contracts	—	366	18	384
Oil and gas derivative option contracts	—	—	524	524
Interest rate swap	—	2	—	2
Total	$ 6	$368	$601	$975
As of December 31, 2009:				
Money market fund investments	$15	$ —	$. —	$ 15
Investments available-for-sale:				
Equity securities	7	—	—	7
Auction rate securities	—	—	40	40
Oil and gas derivative swap contracts	—	119	(14)	105
Oil and gas derivative option contracts	—	—	173	173
Interest rate swap	—	3	—	3
Total	$22	$122	$199	$343

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). 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, 2009, we continued to hold $40 million of auction rate securities maturing beginning in 2033 that are classified as a Level 3 fair value measurement. This amount reflects a decrease in the fair value of these investments of $15 million ($10 million net of tax), recorded under the caption "Accumulated other comprehensive income (loss)" on our consolidated balance sheet. Since there has been no effective mechanism for selling these securities, we reclassified them from short-term to long-term investments during the second quarter of 2008. The debt instruments underlying these investments are 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 auctions succeed, the issuer calls the securities or the securities mature. Our current available borrowing capacity under our credit arrangements provides us the liquidity to continue to hold these securities.

The following 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 year ended December 31, 2009:

	Investments	Derivatives	Total
		(In millions)	
Balance at January 1, 2009	$ 59	$ 542	$ 601
Total realized or unrealized gains (losses):			
Included in earnings	—	(55)	(55)
Included in other comprehensive income (loss)	2	—	2
Purchases, issuances and settlements	(21)	(328)	(349)
Transfers in and out of Level 3	—	—	—
Balance at December 31, 2009	$ 40	$ 159	$ 199
Change in unrealized gains (losses) relating to investments and derivatives still held at December 31, 2009	$ —	$ (95)	$ (95)

Fair Value of Debt

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

	December 31, 2009	December 31, 2008
	(in millions)	
7⅝% Senior Notes due 2011	$180	$159
6⅝% Senior Subordinated Notes due 2014	333	255
6⅝% Senior Subordinated Notes due 2016	553	402
7⅛% Senior Subordinated Notes due 2018	605	468

Amounts outstanding under our credit arrangements at December 31, 2009 and 2008 are stated at cost, which approximates fair value. Please see Note 9, "Debt."

9. Debt:

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

	December 31, 2009	December 31, 2008
	(In millions)	
Senior unsecured debt:		
Revolving credit facility:		
LIBOR based loans	$ 384	$ 514
Total revolving credit facility	384	514
Money market lines of credit(1)	—	47
Total credit arrangements	384	561
7⅝% Senior Notes due 2011	175	175
Fair value of interest rate swap(2)	3	2
Total senior unsecured notes	178	177
Total senior unsecured debt	562	738
6⅝% Senior Subordinated Notes due 2014	325	325
6⅝% Senior Subordinated Notes due 2016	550	550
7⅛% Senior Subordinated Notes due 2018	600	600
Total debt	$2,037	$2,213

(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.

(2) We have hedged $50 million principal amount of our $175 million 7⅝% Senior Notes due 2011. The hedge provides for us to pay variable and receive fixed interest payments. See Note 5, "Derivative Financial Instruments — *Interest Rate Swap*."

Credit Arrangements

We have a revolving credit facility which provides for loan commitments of $1.25 billion from a syndicate of more than 15 financial institutions, led by JPMorgan Chase Bank, as agent, and matures June 2012. However, the amount that we can borrow under the facility could be limited by changing expectations of future oil and gas prices because the maximum amount that we can borrow under the facility is determined by our lenders annually each May (and may be adjusted at the option of our lenders in the case of certain acquisitions or divestitures) using a process that takes into account the value of our estimated reserves and hedge position and the lenders' commodity price assumptions. In the future, total loan commitments under the facility could be increased to a maximum of $1.65 billion if the existing lenders increase their individual loan commitments or new financial institutions are added to the facility. We do not believe we could access such additional capacity in the current credit market. As of December 31, 2009, the largest commitment was 16% 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 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 or (b) a base Eurodollar rate substantially equal to the London

Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (87.5 basis points per annum at December 31, 2009).

We pay commitment fees on available but undrawn amounts based on a grid of our debt rating (0.175% per annum at December 31, 2009). We incurred fees under this arrangement of approximately $1 million for the year ended December 31, 2009 and $2 million for each of the years ended December 31, 2008 and 2007, which are recorded in interest expense on our consolidated statement of income.

Our credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0; maintenance of a ratio of total debt to 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) of at least 3.5 to 1.0. In addition, for as long as our debt rating is below investment grade, we must maintain a ratio of the calculated net present value of our oil and gas reserves to total debt of at least 1.75 to 1.00. For purposes of this ratio, total debt includes only 50% of the principal amount of our senior subordinated notes. At December 31, 2009, we were in compliance with all of our debt covenants.

As of December 31, 2009, we had $16 million of undrawn letters of credit outstanding under our credit facility. Letters of credit are subject to an issuance fee of 12.5 basis points and annual fees based on a grid of our debt rating (87.5 basis points at December 31, 2009). We incurred fees of less than $1 million for each of the years ended December 31, 2009, 2008 and 2007, which are recorded in interest expense on our consolidated statement of income.

Subject to compliance with the restrictive covenants in our credit facility, we also have a total of $120 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.

Our credit facility and senior and senior subordinated notes contain standard events of default and, if any such events of default were to occur, our lenders could terminate future lending commitments under the credit facility and our lenders could declare the outstanding borrowings due and payable. In addition, our credit facility, 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 February 2001, we issued $175 million aggregate principal amount of our 7⅝% Senior Notes due 2011.

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

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

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

On February 19, 2010, we announced that we had accepted for purchase and payment approximately $143 million of our $175 million aggregate principal amount of 7⅝% Senior Notes due 2011 pursuant to a tender offer and consent solicitation that began on January 20, 2010. We funded the tender offer with a portion of the proceeds from our January 25, 2010 issuance of $700 million aggregate principal amount of our 6⅞% Senior Subordinated Notes due 2020. See Note 19, "Subsequent Events."

Senior Subordinated Notes

In August 2004, we issued $325 million aggregate principal amount of our 6⅝% Senior Subordinated Notes due 2014. The net proceeds from the offering were $323 million.

In April 2006, we issued $550 million aggregate principal amount of our 6⅝% Senior Subordinated Notes due 2016. The net proceeds from the offering were $545 million.

In May 2008, we issued $600 million aggregate principal amount of our 7⅛% Senior Subordinated Notes due 2018. We received net proceeds from the offering of $592 million.

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

We may redeem some or all of our 6⅝% notes due 2014 at any time on or after September 1, 2009 and some or all of our 6⅝% notes due 2016 at any time on or after April 15, 2011, in each case, at a redemption price stated in the applicable indenture governing the notes. We also may redeem all but not part of our 6⅝% notes due 2016 prior to April 15, 2011, at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption.

We may redeem some or all of our 7⅛% notes at any time on or after May 15, 2013 at a redemption price stated in the indenture governing the notes. Prior to May 15, 2013, we may redeem all, but not part, of our 7⅛% notes at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. In addition, before May 15, 2011, we may redeem up to 35% of the original principal amount of our 7⅛% notes with the net cash proceeds of certain sales of our common stock at 107.125% of the principal amount, plus accrued and unpaid interest to the date of redemption.

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

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

On January 25, 2010, we sold $700 million of 6⅞% Senior Subordinated Notes due 2020 and received net proceeds of $686 million. These notes were issued at 99.109% of par to yield 7%. We used $294 million of the net proceeds to repay all of our then outstanding borrowings under our credit facility, $215 million to fund the acquisition of assets from TXCO Resources Inc. and we tendered for approximately $143 million of our outstanding 7⅝% Senior Notes due 2011. See Note 19, "Subsequent Events."

10. Income Taxes:

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

	For the Year Ended December 31, 2009	2008	2007
	(In millions)		
U.S.	$(1,033)	$(572)	$269
Foreign	148	37	25
Total income (loss) before income taxes	$ (885)	$(535)	$294

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

	For the Year Ended December 31, 2009	2008	2007
	(In millions)		
Current taxes:			
U.S. federal	$ 4	$ 1	$ 85
U.S. state	—	—	3
Foreign	44	35	4
Deferred taxes:			
U.S. federal	(352)	(165)	7
U.S. state	(28)	(34)	8
Foreign	(11)	1	15
Total provision (benefit) for income taxes	$(343)	$(162)	$122

The provision (benefit) for income taxes for each of the years in the three-year period ended December 31, 2009 was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	For the Year Ended December 31, 2009	2008	2007
	(In millions)		
Amount computed using the statutory rate	$(310)	$(187)	$103
Increase (decrease) in taxes resulting from:			
State and local income taxes, net of federal effect	(18)	(22)	7
Net effect of different tax rates in non-U.S. jurisdictions	5	(1)	10
Goodwill impairment	—	22	—
Valuation allowance	(24)	24	—
Other	4	2	2
Total provision (benefit) for income taxes	$(343)	$(162)	$122

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

	December 31, 2009			December 31, 2008		
	U.S.	Foreign	Total	U.S.	Foreign	Total
	(In millions)					
Deferred tax asset:						
Net operating loss carryforwards	$ 377	$ 6	$ 383	$ 324	$ 6	$ 330
Alternative minimum tax credit	90	—	90	84	—	84
Stock compensation	28	—	28	23	—	23
Marketable securities	6	—	6	6	—	6
Oil and gas properties	—	26	26	—	24	24
Valuation allowance	—	(6)	(6)	—	(30)	(30)
Other	28	—	28	3	—	3
Deferred tax asset	529	26	555	440	—	440
Deferred tax liability:						
Commodity derivatives	(12)	—	(12)	(147)	—	(147)
Oil and gas properties	(998)	(40)	(1,038)	(1,156)	(21)	(1,177)
Deferred tax liability	(1,010)	(40)	(1,050)	(1,303)	(21)	(1,324)
Net deferred tax liability	(481)	(14)	(495)	(863)	(21)	(884)
Less net current deferred tax liability	(87)	—	(87)	(226)	—	(226)
Noncurrent deferred tax liability	$ (394)	$(14)	$ (408)	$ (637)	$(21)	$ (658)

As of December 31, 2009, and 2008 we had net operating loss (NOL) carryforwards for federal and state income tax purposes of approximately $1.0 billion for 2009, and $900 million for 2008, respectively, which may be used in future years to offset taxable income. NOL carryforwards of $273 million are subject to annual limitations due to stock ownership changes. To the extent not utilized, the NOL carryforwards will begin to expire during the years 2019 through 2029. Utilization of NOL carryforwards is dependent upon generating sufficient future taxable income in the appropriate jurisdictions within the carryforward period.

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

As of December 31, 2009 and 2008, we had NOL carryforwards for international income tax purposes of approximately $17 million. We currently estimate that we will not be able to utilize our international NOLs because we do not have sufficient estimated future taxable income in the appropriate jurisdictions. Therefore, valuation allowances have been established for these items. Estimates of future taxable income can be significantly affected by changes in oil and gas prices, estimates of the timing and amount of future production and estimates of future operating and capital costs.

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

	For the Year Ended December 31,		
	2009	2008	2007
	(In millions)		
Balance at the beginning of the year	$(30)	$ (6)	$(6)
Charged to provision for income taxes:			
Malaysia ceiling test writedown	24	(24)	—
Balance at the end of the year	$ (6)	$(30)	$(6)

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

11. Stock-Based Compensation:

On May 7, 2009, at our 2009 annual meeting of stockholders, our stockholders approved the Newfield Exploration Company 2009 Omnibus Stock Plan (the "2009 Omnibus Stock Plan"), and our 2000 omnibus stock plan, 2004 omnibus stock plan and 2007 omnibus stock plan (which were used for equity grants to employees) were terminated such that no new grants will be made under those previous plans. On May 7, 2009, at our 2009 annual meeting of stockholders, our stockholders also approved the Newfield Exploration Company 2009 Non-Employee Director Restricted Stock Plan, and our previous plan for restricted stock awards to non-employee directors was terminated such that no new grants will be made under the previous plan. Outstanding awards under those previous plans were not impacted by the termination of those previous plans. 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.

Historically, we have used unissued shares of stock when stock options are exercised. Beginning in 2009, we began to utilize treasury shares when stock options are exercised, restricted stock is issued or restricted stock units vest.

Shares available for grant under our 2009 Omnibus Stock Plan are reduced by 1.5 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, 2009, we had approximately (1) 2.4 million additional shares available for issuance pursuant to our existing employee and director plans if all future employee awards under our 2009 Omnibus Stock Plan are stock options, or (2) 1.7 million additional shares available for issuance pursuant to our existing employee and director plans if all future employee awards under our 2009 Omnibus Stock Plan are restricted stock or restricted stock units. Thus far, all awards under our 2009 Omnibus Stock Plan have been restricted stock unit awards.

For the years ended December 31, 2009, 2008 and 2007, we recorded stock-based compensation expense of $45 million, $37 million and $34 million, respectively, for all plans. Of these amounts, $17 million, $11 million and $10 million, respectively, were capitalized in oil and gas properties.

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 compensation expense. We did not realize an excess tax benefit from stock compensation for 2009 or 2008 because we do not anticipate having sufficient taxable income to fully realize the deduction. The amount credited to additional paid in capital for 2007 was $14 million.

As of December 31, 2009, we had approximately $56 million of total unrecognized compensation expense related to unvested stock-based compensation awards. This compensation expense is expected to be recognized on a straight-line basis over the applicable remaining vesting period. The full amount is expected to be recognized within approximately five years.

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

The following table provides information about stock option activity for the years ended December 31, 2009, 2008 and 2007:

	Number of Shares Underlying Options	Weighted Average Exercise Price per Share	Weighted Average Grant Date Fair Value per Share	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value(1)
	(In millions)			(In years)	(In millions)
Outstanding at December 31, 2006 . . .	5.6	$23.68		6.3	$124
Granted	—	—	—		
Exercised	(1.4)	20.94			41
Forfeited.	(0.4)	29.45			
Outstanding at December 31, 2007 . . .	3.8	24.21		5.6	108
Granted(2)	0.7	48.45	$16.30		
Exercised	(0.8)	22.38			29
Forfeited.	(0.2)	33.83			
Outstanding at December 31, 2008 . . .	3.5	28.74		5.5	3
Granted	—	—	—		
Exercised	(0.5)	21.07			9
Forfeited.	(0.1)	32.74			
Outstanding at December 31, 2009 . . .	2.9	$29.82		4.7	$ 56
Exercisable at December 31, 2009 . . .	2.3	$26.50		4.1	$ 53

(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.

(2) The fair value of the options granted during 2008 was determined using the Black-Scholes option valuation model, assuming no dividends, a risk-free weighted average interest rate of 2.83%, an expected life of 5.2 years and weighted average volatility of 31.7%.

On December 31, 2009, the last reported sales price of our common stock on the New York Stock Exchange was $48.23 per share.

The following table summarizes information about stock options outstanding and exercisable at December 31, 2009:

	Options Outstanding			Options Exercisable	
	Number of Shares Underlying Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price per Share	Number of Shares Underlying Options	Weighted Average Exercise Price per Share
	(In millions)	(In years)		(In millions)	
$12.51 to $17.50	0.6	2.6	$16.63	0.6	$16.63
17.51 to 22.50	0.3	2.3	18.86	0.3	18.86
22.51 to 27.50	0.4	4.2	24.76	0.4	24.76
27.51 to 35.00	0.8	5.0	31.22	0.7	31.08
35.01 to 41.72	0.2	5.3	37.49	0.1	37.45
41.73 to 48.45	0.6	8.1	48.45	0.2	48.45
	2.9	4.7	$29.82	2.3	$26.50

Restricted Stock. At December 31, 2009, 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, 2009, our employees held 0.8 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).

Under our non-employee director restricted stock plan as in effect on December 31, 2009, immediately after each annual meeting of our stockholders, each of our non-employee directors then in office receives a number of shares of restricted stock determined by dividing a specified market value by the closing sales price of our common stock on the date of the annual meeting. In addition, each non-employee director who is appointed by our Board (not in connection with an annual meeting of stockholders) is granted restricted stock with the same market value as used for the previous annual meeting, with the number of shares of restricted stock determined by dividing the market value by the closing sales price of our common stock on the date of appointment. With respect to grants made on the date of our 2009 annual meeting of stockholders, the market value of the award to non-employee directors was $100,000. With respect to each annual meeting after our 2009 annual meeting, the Nominating & Corporate Governance Committee of our Board will determine the market value of the award by resolution in advance of the meeting. For 2010, the market value of the award will be $150,000. If the Chairman of the Board is a non-employee director, the award amount may be greater than the award amount for the other non-employee directors. If a non-employee director Chairman of the Board is appointed not in connection with an annual meeting, the award amount will be determined by the Nominating & Corporate Governance Committee on the date of appointment. Restrictions on restricted stock granted pursuant to the plan generally lapse on the day before the first annual meeting of stockholders after the date of grant. An aggregate of 200,000 shares of restricted stock were initially available for issuance pursuant to our non-employee director restricted stock plan. As of December 31, 2009, there were 166,637 shares of restricted stock available for grant and 33,363 shares of restricted stock outstanding under our non-employee director restricted stock plan.

The following table provides information about restricted stock and restricted stock unit activity for the years ended December 31, 2009, 2008 and 2007:

	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 December 31, 2006	667	1,516	2,183	$26.16
Granted	711	293	1,004	38.04
Forfeited	(120)	(111)	(231)	34.22
Vested	(97)	(84)	(181)	27.21
Non-vested shares outstanding at December 31, 2007	1,161	1,614	2,775	29.77
Granted	975	—	975	42.44
Forfeited	(388)	(405)	(793)	26.86
Vested	(69)	(1)	(70)	42.11
Non-vested shares outstanding at December 31, 2008	1,679	1,208	2,887	34.58
Granted	1,124	—	1,124	24.03
Forfeited	(77)	(316)	(393)	26.84
Vested	(302)	(110)	(412)	36.07
Non-vested shares outstanding at December 31, 2009	2,424	782	3,206	$31.60

The total fair value of restricted stock and restricted stock units that vested during the years ended December 31, 2009, 2008 and 2007 was $14.8 million, $3.0 million and $4.9 million, respectively.

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.

12. Pension Plan Obligation:

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

The following tables summarize changes in the benefit obligation, the plan assets and the funded status of our pension plan as well as the components of net periodic benefit costs, including key assumptions. The measurement dates for plan assets and obligations were December 31, 2009 and 2008.

	2009	2008
	(In millions)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$(34)	$(34)
Interest cost	(2)	(2)
Settlements	40	—
Benefits paid	1	2
Actuarial loss	(5)	—
Benefit obligation at end of year	$ —	$(34)
Change in plan assets:		
Fair value of plan assets at beginning of year	$ 39	$ 29
Actual return on plan assets	—	10
Employer contributions	2	2
Settlements	(40)	(1)
Benefits paid	(1)	(1)
Fair value of plan assets at end of year	$ —	$ 39
Minimum liability recognition:		
Accumulated benefit obligation (ABO)		$(34)
Fair value of plan assets		39
Funded ABO		$ 5
Reconciliation of funded status:		
Projected benefit obligation (PBO)		$(34)
Fair value of plan assets		39
Funded status		5
Unrecognized net gain		(5)
Accrued pension liability (*before* minimum liability recognition)		—
Transition adjustment required to recognize minimum liability:		
Accumulated other comprehensive gain		5
Accrued pension asset (*after* minimum liability recognition)		$ 5
Check on reconciliation of accrued pension cost:		
Accrued pension asset (liability) at beginning of year	$ 5	$ (5)
Company contributions	—	2
Change in accumulated other comprehensive (income) loss	(5)	8
Accrued pension asset at end of year	$ —	$ 5

	Year Ended December 31,		
	2009	2008	2007
	(In millions)		
Net periodic benefit cost:			
Interest cost	$ 2	$ 2	$ 2
Expected return on plan assets	(3)	(2)	(2)
Net periodic benefit income	(1)	—	—
Settlement loss	3	—	—
Total periodic benefit cost	$ 2	$ —	$ —
Key Assumptions for Expense Purposes:			
Discount rate assumption	6.24%	6.46%	5.75%
Expected return on plan assets	—	8.00%	8.00%
Key Assumptions for Disclosure Purposes:			
Discount rate assumption	—	6.24%	6.46%
Expected return on plan assets	—	8.00%	8.00%

At December 31, 2008, the plan's assets consisted 100% of cash and money market funds.

13. 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, 2009, both our accumulated benefit obligation and our accrued benefit costs were $6 million. Our net periodic benefit cost has been approximately $1 million per year.

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

2010 — 2014	$1
2015 — 2019	3

Incentive Compensation Plan

Our 2003 incentive compensation plan provides for the creation each calendar year of an award pool that is generally equal to 5% of our adjusted net income (as defined in the plan) plus the revenues attributable to an overriding royalty interest bearing on the interests of investors that participate in certain of our activities. The plan is administered by the Compensation & Management Development Committee of our Board of Directors and award amounts (other than for the chief executive officer) are recommended by our chief executive officer. The plan provides the committee with the discretion to make adjustments to our adjusted net income, as defined in the plan, for purposes of determining the annual award pool. Adjustments may be made for extraordinary or other unusual items or other items not contemplated at the time the plan was adopted, such as changes in generally accepted accounting principles, ceiling test writedowns or other non-recurring items, as the committee determines in its sole discretion. All employees are eligible for awards if employed on both October 1 and December 31 of the performance period. Awards under the plan may have both a current and a long-term component. Long-term cash awards are paid in four annual installments, each installment consisting of 25% of the long-term award, plus interest. Total expense under the plan for the years ended December 31, 2009, 2008 and 2007 was $28 million, $35 million and $51 million, respectively.

401(k) and Deferred Compensation Plans

We sponsor a 401(k) profit sharing plan under Section 401(k) of the Internal Revenue Code. This plan covers all of our employees other than employees of our foreign subsidiaries. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee's salary, subject to limitations imposed by the Internal Revenue Service. 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 totaled $5 million for the years ended December 31, 2009 and 2008 and $4 million for the year ended December 31, 2007.

14. Commitments and Contingencies:

Lease Commitments

We have various commitments under non-cancellable operating lease agreements for office space, equipment and drilling rigs. The majority of these commitments are related to multi-year contracts for drilling rigs that are accounted for as capital additions to our oil and gas properties. Future minimum payments required under these leases as of December 31, 2009 are as follows (in millions):

Year Ending December 31,	
2010	$ 63
2011	11
2012	9
2013	9
2014	9
Thereafter	26
Total minimum lease payments	$127

Rent expense with respect to our lease commitments for office space for the years ended December 31, 2009, 2008 and 2007 was $9 million, $8 million and $6 million, respectively.

Other Commitments

As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work-related commitments for, among other things, drilling wells, obtaining and processing seismic data, natural gas transportation and fulfilling other cash commitments. At December 31, 2009, these work-related commitments totaled $508 million and were comprised of $380 million in our domestic business and $128 million internationally. Our domestic obligation relates to a 10-year firm transportation agreement for our Mid-Continent production. This obligation is subject to the completion of construction, which is expected during the second quarter of 2010, and upon required regulatory approvals. The timing of maturity of this obligation cannot be accurately predicted. In addition, we have a domestic contractual obligation of $233 million for other firm transportation agreements, of which $31 million relates to 2010, and the remainder relates to 2011 or thereafter.

As of December 31, 2009, we have delivery commitments through 2011 to deliver to third party purchasers approximately 100,000 MMBtu of our daily production, principally from our Mid-Continent division. Given the size of our proved natural gas reserves and production capacity in our Mid-Continent division, we currently believe that we have sufficient reserves and production to fulfill these delivery commitments.

Litigation

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

15. 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, 2009, 2008 and 2007 for our continuing operations. 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, 2009:					
Oil and gas revenues	$ 972	$321	$ 45	$—	$ 1,338
Operating expenses:					
Lease operating	203	51	5	—	259
Production and other taxes	33	25	5	—	63
Depreciation, depletion and amortization	463	111	13	—	587
General and administrative	139	4	1	—	144
Ceiling test writedown	1,344	—	—	—	1,344
Other	8	—	—	—	8
Allocated income taxes	(438)	49	5	—	
Net income (loss) from oil and gas properties	$ (780)	$ 81	$ 16	$—	
Total operating expenses					2,405
Loss from operations					(1,067)
Interest expense, net of interest income, capitalized interest and other					(70)
Commodity derivative income					252
Loss before income taxes					$ (885)
Total long-lived assets	$4,668	$379	$155	$ 3	$ 5,205
Additions to long-lived assets	$1,275	$ 98	$ 59	$—	$ 1,432

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Year Ended December 31, 2008:					
Oil and gas revenues	$1,861	$305	$ 59	$—	$2,225
Operating expenses:					
Lease operating	210	52	3	—	265
Production and other taxes	60	86	11	—	157
Depreciation, depletion and amortization	597	88	12	—	697
General and administrative	136	2	2	1	141
Ceiling test and other impairments	1,792	71	—	—	1,863
Other	4	—	—	—	4
Allocated income taxes	(357)	2	8	—	
Net income (loss) from oil and gas properties	$ (581)	$ 4	$ 23	$ (1)	
Total operating expenses					3,127
Loss from operations					(902)
Interest expense, net of interest income, capitalized interest and other					(41)
Commodity derivative income					408
Loss before income taxes					$ (535)
Total long-lived assets	$5,212	$390	$109	$ 3	$5,714
Additions to long-lived assets	$2,065	$182	$ 43	$ 1	$2,291

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Year Ended December 31, 2007:					
Oil and gas revenues	$1,626	$111	$46	$—	$1,783
Operating expenses:					
Lease operating	281	29	4	—	314
Production and other taxes	73	24	4	—	101
Depreciation, depletion and amortization	643	28	11	—	682
General and administrative	150	2	3	—	155
Allocated income taxes	172	11	8	—	
Net income from oil and gas properties	$ 307	$ 17	$16	$—	
Total operating expenses					1,252
Income from operations					531
Interest expense, net of interest income, capitalized interest and other					(49)
Commodity derivative expense					(188)
Income from continuing operations before income taxes					$ 294
Total long-lived assets	$5,480	$365	$76	$ 2	$5,923
Additions to long-lived assets	$2,409	$216	$24	$ 2	$2,651

16. Supplemental Cash Flow Information:

	Year Ended December 31, 2009	2008	2007
	(In millions)		
Cash payments:			
Interest payments, net of interest capitalized of $51, $60 and $47 during 2009, 2008 and 2007, respectively	$ 74	$ 47	$ 56
Income tax payments	3	6	87
Non-cash items excluded from the statement of cash flows:			
(Increase) decrease in accrued capital expenditures	$ 12	$ 33	$ (24)
(Increase) decrease in asset retirement costs	(19)	(16)	194

17. Related Party Transaction:

David A. Trice, our Chairman and former Chief Executive Officer, and Susan G. Riggs, our Treasurer, are minority owners of Huffco International L.L.C. In May 1997, before Mr. Trice 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 2009, Newfield China paid $2 million 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 interests (through Huffco) in Newfield China's preferred shares held by Mr. Trice and Ms. Riggs had a net present value of approximately $405,000 and $156,000, respectively, at December 31, 2009.

18. Stockholder Rights Plan:

In 1999, we adopted a stockholders rights plan. The plan was designed to ensure that all of our stockholders receive fair and equal treatment if a takeover of our company was proposed. It included safeguards against partial or two-tiered tender offers, squeeze-out mergers, and other abusive takeover tactics. The plan expired by its terms on February 22, 2009.

19. Subsequent Events:

On February 11, 2010, we acquired certain of TXCO Resources Inc.'s assets in the Maverick Basin of southwest Texas for $215 million.

On January 25, 2010, we sold $700 million of 6⅞% Senior Subordinated Notes due 2020 and received net proceeds of $686 million. These notes were issued at 99.109% of par to yield 7%. We used $294 million of the net proceeds to repay all of our then outstanding borrowings under our credit facility, $215 million to fund the acquisition of assets from TXCO Resources Inc. as described above and we tendered for approximately $143 million of our outstanding 7⅝% Senior Notes due 2011 as described below.

In conjunction with the issuance of the Senior Subordinated Notes described in the immediately preceding paragraph, we announced a cash tender offer and consent solicitation for any, and all, of our $175 million aggregate principal amount of 7⅝% Senior Notes due 2011. On February 19, 2010, we announced that we had accepted for purchase and payment approximately $143 million of the Senior Notes pursuant to the tender offer and consent solicitation.

20. Quarterly Results of Operations (Unaudited):

The results of operations by quarter for the years ended December 31, 2009 and 2008 are as follows:

	2009 Quarter Ended			
	March 31	June 30	September 30	December 31(1)
	(In millions, except per share data)			
Oil and gas revenues	$ 262	$ 287	$ 375	$ 414
Income (loss) from operations(2)	(1,355)	39	112	137
Net income (loss)	(694)	(39)	78	113
Basic earnings (loss) per common share(3)	$ (5.35)	$(0.30)	$0.59	$0.87
Diluted earnings (loss) per common share	$ (5.35)	$(0.30)	$0.58	$0.86

	2008 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil and gas revenues	$ 515	$ 691	$ 680	$ 338
Income (loss) from operations(4)	216	378	345	(1,842)
Net income (loss)	(64)	(244)	724	(789)
Basic earnings (loss) per common share(3)	$(0.50)	$(1.89)	$5.59	$ (6.09)
Diluted earnings (loss) per common share	$(0.50)	$(1.89)	$5.48	$ (6.09)

(1) Effective December 31, 2009, we adopted recently revised authoritative accounting and disclosure requirements for oil and gas reserves. As a result, the fourth quarter of 2009 amounts are not on a basis comparable to prior periods.

(2) Income (loss) from operations for the first quarter of 2009 includes a full cost ceiling test writedown of $1.3 billion.

(3) The sum of the individual quarterly earnings (loss) per share may not agree with year-to-date earnings 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.

(4) Income (loss) from operations for the fourth quarter of 2008 includes a full cost ceiling test writedown of $1.8 billion and a goodwill impairment of $62 million.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES — UNAUDITED

Costs Incurred

Costs incurred for oil and gas property acquisitions, exploration and development for each of the years in the three-year period ended December 31, 2009 are as follows:

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
2009:					
Property acquisitions:					
Unproved	$ 114	$ —	$—	$—	$ 114
Proved	33	—	—	—	33
Exploration(1)	817	38	47	—	902
Development(2)	311	60	12	—	383
Total costs incurred(3)	$1,275	$ 98	$59	$—	$1,432
2008:					
Property acquisitions:					
Unproved	$ 235	$ 9	$ 1	$—	$ 245
Proved	128	—	—	—	128
Exploration(1)	1,294	53	28	1	1,376
Development(2)	408	120	14	—	542
Total costs incurred(3)	$2,065	$182	$43	$ 1	$2,291
2007(4):					
Property acquisitions(5):					
Unproved	$ 258	$ —	$ 2	$—	$ 260
Proved	479	—	—	—	479
Exploration(1)	1,320	47	11	1	1,379
Development(2)	353	169	11	—	533
Total costs incurred(3)	$2,410	$216	$24	$ 1	$2,651

(1) Includes $181 million, $351 million and $240 million of domestic costs for non-exploitation activities for 2009, 2008 and 2007, respectively; $21 million, $20 million and $23 million of Malaysia costs for non-exploitation activities for 2009, 2008 and 2007, respectively; $47 million, $28 million and $11 million of China costs for non-exploitation activities for 2009, 2008 and 2007, respectively; and $1 million per year of Other International costs for non-exploitation activities for 2008 and 2007. Non-exploitation activities for Other International were immaterial for 2009.

(2) Includes $19 million, $15 million and $21 million for 2009, 2008 and 2007, 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:

	2009	2008	2007
		(In millions)	
Proceeds from property sales — Domestic	$ 33	$ 17	$1,295
Asset retirement costs associated with property sales	—	—	216
Insurance settlement proceeds — Domestic	7	—	1
Ceiling test writedown — Domestic	1,344	1,730	—
Ceiling test writedown — Malaysia	—	71	—
	$1,384	$1,818	$1,512

(4) In October 2007, we sold all our interests in the U.K. North Sea. As a result, the costs incurred for U.K. activities in 2007 for exploration and development of $2 million and $24 million, respectively, are excluded and classified as discontinued operations. The 2007 U.K. discontinued operations include $3 million of asset retirement costs.

(5) Includes $578 million related to our acquisition of Stone Energy's Rocky Mountain assets.

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, 2009:

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
December 31, 2009:					
Proved properties	$ 8,500	$ 561	$121	$—	$ 9,182
Unproved properties	982	73	73	3	1,131
	9,482	634	194	3	10,313
Accumulated depreciation, depletion and amortization	(4,814)	(255)	(39)	—	(5,108)
Net capitalized costs	$ 4,668	$ 379	$155	$ 3	$ 5,205
December 31, 2008:					
Proved properties	$ 8,457	$ 473	$102	$—	$ 9,032
Unproved properties	1,133	63	33	3	1,232
	9,590	536	135	3	10,264
Accumulated depreciation, depletion and amortization	(4,378)	(146)	(26)	—	(4,550)
Net capitalized costs	$ 5,212	$ 390	$109	$ 3	$ 5,714
December 31, 2007:					
Proved properties	$ 8,240	$ 310	$ 82	$—	$ 8,632
Unproved properties	1,031	116	10	2	1,159
	9,271	426	92	2	9,791
Accumulated depreciation, depletion and amortization	(3,791)	(61)	(16)	—	(3,868)
Net capitalized costs	$ 5,480	$ 365	$ 76	$ 2	$ 5,923

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.

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

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

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

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

Due to the extent of our domestic and international oil and gas activities and the limited time interval allowed for preparing our annual report on Form 10-K, it was not practical to prepare estimates of oil and gas reserves using end of period prices and to generate discounted cash flow models for estimates of proved reserves using both the previous rules and the new rules. Therefore, it was not practical to quantify the volumetric impact of the change in reserves rules and methodology or the impact, if any, on our full-cost ceiling test or depletion rate.

Reserves Estimates. All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. The preparation of our oil and gas reserves estimates is completed in accordance with our prescribed internal control procedures, which include verification of data input into reserves forecasting and economics evaluation software, as well as multi-discipline management reviews. The technical employee responsible for overseeing the preparation of the reserves estimates has a Bachelor of Science in Petroleum Engineering, with more than 25 years of experience (including 15 years of experience in reserve estimation) and is a Registered Professional Engineer in Texas. For additional information regarding our reserves estimation process please see Items 1 and 2, "*Business and Properties* — Proved and Probable Reserves."

Estimated Net Quantities of Proved Oil and Gas Reserves

The following table sets forth our total net proved reserves and our total net proved developed reserves as of December 31, 2006, 2007, 2008 and 2009 and the changes in our total net proved reserves during the three-year period ended December 31, 2009:

	Oil, Condensate and Natural Gas Liquids (MMBbls)				Natural Gas (Bcf)	Total Natural Gas Equivalents (Bcfe)				
	Domestic	Malaysia[1]	China[1]	Total	Domestic	Domestic	Malaysia	China	Discontinued Operations – United Kingdom	Total
Proved developed and undeveloped reserves as of:										
December 31, 2006	93	16	5	114	1,535	2,092	93	32	55	2,272
Revisions of previous estimates	—	—	1	1	(18)	(16)	(1)	5	—	(12)
Extensions, discoveries and other additions	13	—	—	13	583	659	1	—	—	660
Purchases of properties[2]	10	—	—	10	163	221	—	—	—	221
Sales of properties[3]	(13)	—	—	(13)	(268)	(343)	—	—	(53)	(396)
Production	(8)	(2)	(1)	(11)	(185)	(232)	(10)	(5)	(2)	(249)
December 31, 2007	95	14	5	114	1,810	2,381	83	32	—	2,496
Revisions of previous estimates	(4)	7	1	4	(93)	(116)	44	5	—	(67)
Extensions, discoveries and other additions	26	5	2	33	534	687	29	8	—	724
Purchases of properties	1	—	—	1	29	34	—	—	—	34
Sales of properties	—	—	—	—	(2)	(2)	—	—	—	(2)
Production	(7)	(4)	(1)	(12)	(168)	(210)	(21)	(4)	—	(235)
December 31, 2008	111	22	7	140	2,110	2,774	135	41	—	2,950
Revisions of previous estimates	(3)	—	(1)	(4)	(358)	(376)	—	(8)	—	(384)
Extensions, discoveries and other additions[4]	38	8	2	48	1,045	1,270	48	13	—	1,331
Purchases of properties	1	—	—	1	6	11	—	—	—	11
Sales of properties	(2)	—	—	(2)	(26)	(35)	—	—	—	(35)
Production	(8)	(5)	(1)	(14)	(172)	(220)	(32)	(5)	—	(257)
December 31, 2009	137	25	7	169	2,605	3,424	151	41	—	3,616
Proved developed reserves as of:										
December 31, 2006	61	2	2	65	1,094	1,459	14	11	—	1,484
December 31, 2007	61	6	4	71	1,136	1,505	38	23	—	1,566
December 31, 2008	65	12	5	82	1,336	1,727	72	28	—	1,827
December 31, 2009	70	10	5	85	1,397	1,820	60	28	—	1,908

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

(2) Substantially all of the purchases of domestic oil and gas reserves in 2007 relate to our June 2007 acquisition of Stone Energy's Rocky Mountain assets.

(3) Substantially all of the sales of oil and gas reserves in 2007 relate to the sale of our shallow water Gulf of Mexico assets and the sale of our coal bed methane assets in the Cherokee Basin of Oklahoma.

(4) Domestic extension, discoveries and other additions in 2009 includes 693 Bcfe of additions resulting from the change in the SEC definition of proved reserves, expanding proved undeveloped reserve locations beyond one direct offset away from producing wells. Such locations exist primarily in our Woodford Shale and Monument Butte fields.

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

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

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

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

Under the standardized measure, future cash inflows were estimated by applying the prices used in estimating our proved oil and gas reserves to the year-end quantities of those reserves. Future cash inflows do not reflect the impact of open hedge positions. See Note 5, "Derivative Financial Instruments." Future cash inflows were reduced by estimated future development, abandonment and production costs based on year-end costs in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying year-end statutory tax rates to aggregate future pre-tax net cash flows reduced by the tax basis of the properties involved and tax carryforwards. The standardized measure is derived from using a discount rate of 10% a year to reflect the timing of future net cash flows relating to proved oil and gas reserves.

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

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES — UNAUDITED — (Continued)

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

	Domestic	Malaysia	China	Total
		(In millions)		
2009:				
Future cash inflows	$14,738	$1,594	$ 392	$16,724
Less related future:				
Production costs	(3,864)	(701)	(109)	(4,674)
Development and abandonment costs	(3,016)	(245)	(27)	(3,288)
Future net cash flows before income taxes	7,858	648	256	8,762
Future income tax expense	(1,879)	(109)	(52)	(2,040)
Future net cash flows before 10% discount	5,979	539	204	6,722
10% annual discount for estimating timing of cash flows	(3,645)	(133)	(80)	(3,858)
Standardized measure of discounted future net cash flows	$ 2,334	$ 406	$ 124	$ 2,864
2008:				
Future cash inflows	$13,629	$ 879	$ 242	$14,750
Less related future:				
Production costs	(3,782)	(329)	(62)	(4,173)
Development and abandonment costs	(2,510)	(148)	(23)	(2,681)
Future net cash flows before income taxes	7,337	402	157	7,896
Future income tax expense	(1,895)	(18)	(21)	(1,934)
Future net cash flows before 10% discount	5,442	384	136	5,962
10% annual discount for estimating timing of cash flows	(2,897)	(81)	(55)	(3,033)
Standardized measure of discounted future net cash flows	$ 2,545	$ 303	$ 81	$ 2,929
2007:				
Future cash inflows	$18,539	$1,364	$ 408	$20,311
Less related future:				
Production costs	(4,107)	(732)	(115)	(4,954)
Development and abandonment costs	(2,124)	(58)	(21)	(2,203)
Future net cash flows before income taxes	12,308	574	272	13,154
Future income tax expense	(3,854)	(95)	(55)	(4,004)
Future net cash flows before 10% discount	8,454	479	217	9,150
10% annual discount for estimating timing of cash flows	(4,421)	(111)	(87)	(4,619)
Standardized measure of discounted future net cash flows	$ 4,033	$ 368	$ 130	$ 4,531

Set forth in the table below is a summary of the changes in the standardized measure of discounted future net cash flows for our proved oil and gas reserves during each of the years in the three-year period ended December 31, 2009:

	Domestic	Malaysia	China	Discontinued Operations – United Kingdom	Total
			(In millions)		
2009:					
Beginning of the period	$ 2,545	$ 303	$ 81	$ —	$ 2,929
Revisions of previous estimates:					
Changes in prices and costs	(351)	142	55	—	(154)
Changes in quantities	(550)	(1)	(35)	—	(586)
Changes in future development costs	273	13	(8)	—	278
Development costs incurred during the period	303	51	9	—	363
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	572	99	50	—	721
Purchases and sales of reserves in place, net	(23)	—	—	—	(23)
Accretion of discount	336	33	9	—	378
Sales of oil and gas, net of production costs	(807)	(130)	(21)	—	(958)
Net change in income taxes	164	(68)	(19)	—	77
Production timing and other	(128)	(36)	3	—	(161)
Net increase (decrease)	(211)	103	43	—	(65)
End of the period	$ 2,334	$ 406	$124	$ —	$ 2,864
2008:					
Beginning of the period	$ 4,033	$ 368	$130	$ —	$ 4,531
Revisions of previous estimates:					
Changes in prices and costs	(2,558)	(189)	(79)	—	(2,826)
Changes in quantities	(196)	169	13	—	(14)
Changes in future development costs	(10)	(33)	1	—	(42)
Development costs incurred during the period	352	88	13	—	453
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	774	61	18	—	853
Purchases and sales of reserves in place, net	46	—	—	—	46
Accretion of discount	580	44	16	—	640
Sales of oil and gas, net of production costs	(1,230)	(166)	(34)	—	(1,430)
Net change in income taxes	952	58	20	—	1,030
Production timing and other	(198)	(97)	(17)	—	(312)
Net decrease	(1,488)	(65)	(49)	—	(1,602)
End of the period	$ 2,545	$ 303	$ 81	$ —	$ 2,929
2007:					
Beginning of the period	$ 3,186	$ 135	$ 62	$ 64	$ 3,447
Revisions of previous estimates:					
Changes in prices and costs	1,125	173	70	—	1,368
Changes in quantities	(62)	(6)	29	—	(39)
Changes in future development costs	(37)	(22)	—	—	(59)
Development costs incurred during the period	258	112	—	22	392
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	1,341	16	—	—	1,357
Purchases and sales of reserves in place, net	(438)	—	—	(153)	(591)
Accretion of discount	434	22	9	—	465
Sales of oil and gas, net of production costs	(1,082)	(52)	(22)	(7)	(1,163)
Net change in income taxes	(614)	15	(1)	71	(529)
Production timing and other	(78)	(25)	(17)	3	(117)
Net increase (decrease)	847	233	68	(64)	1,084
End of the period	$ 4,033	$ 368	$130	$ —	$ 4,531

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

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2009.

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

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

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. ***Other Information***

None.

PART III

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

The information appearing under the headings "Election of Directors," "Section 16(A) Beneficial Ownership Reporting Compliance," "Corporate Governance — Board of Directors," "Corporate Governance — Committees," "Corporate Governance — Audit Committee," "Corporate Governance — Nominating & Corporate Governance Committee" and "Stockholder Proposals for 2011 Annual Meeting and Director Nominations" in our proxy statement for our 2010 annual meeting of stockholders to be held on May 7, 2010 (the "2010 Proxy Statement") and the information set forth under the heading "Executive Officers of the Registrant" in this report are incorporated herein by reference.

Corporate Code of Business Conduct and Ethics

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

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

Corporate Governance Materials

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

Item 11. ***Executive Compensation***

The information appearing in our 2010 Proxy Statement under the headings "Compensation & Management Development Committee Report" (which is furnished), "Executive Compensation," "Non-Employee Director Compensation" and "Compensation Committee Interlocks and Insider Participation" is incorporated herein by reference.

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

The information appearing in our 2010 Proxy Statement under the headings "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information" is incorporated herein by reference.

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

The information appearing in our 2010 Proxy Statement under the headings "Corporate Governance — Board of Directors," "Corporate Governance — Committees" and "Interests of Management and Others in Certain Transactions" is incorporated herein by reference.

Item 14. ***Principal Accounting Fees and Services***

The information appearing in our 2010 Proxy Statement under the heading "Principal Accountant Fees and Services" is incorporated herein by reference.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

Financial Statements

Reference is made to the index set forth on page 57 of this report.

Financial Statement Schedules

Financial statement schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is provided in the notes to our consolidated financial statements.

Exhibits

Exhibit Number	Title
3.1	— Second Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield's Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.1.1	— Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield's Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	— Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield's Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	— Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, setting forth the terms of the Series A Junior Participating Preferred Stock, par value $0.01 per share (incorporated by reference to Exhibit 3.5 to Newfield's Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-12534))
3.2	— Amended and Restated Bylaws of Newfield (incorporated by reference to Exhibit 3.2 to Newfield's Current Report on Form 8-K filed with the SEC on February 6, 2009 (File No. 1-12534))
4.1	— Senior Indenture dated as of February 28, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield's Current Report on Form 8-K filed with the SEC on February 28, 2001 (File No. 1-12534))
4.1.1	— First Supplemental Indenture, dated as of February 19, 2010, to Senior Indenture dated as of February 28, 2001 between Newfield and U.S. Bank National Association (as successor to First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Newfield's Current Report on Form 8-K filed with the SEC on February 19, 2010 (File No. 1-12534))
4.2	— Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.5 of Newfield's Registration Statement on Form S-3 (Registration No. 333-71348))
4.2.1	— Second Supplemental Indenture, dated as of August 18, 2004, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.6.3 to Newfield's Registration Statement on Form S-4 (Registration No. 333-122157))
4.2.2	— Third Supplemental Indenture, dated as of April 3, 2006, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4.3 of Newfield's Current Report on Form 8-K filed with the SEC on April 3, 2006 (File No. 1-12534))
4.2.3	— Form of Fourth Supplemental Indenture, to be dated as of May 8, 2008, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Newfield's Current Report on Form 8-K filed with the SEC on May 7, 2008 (File No. 1-12534))

Exhibit Number	Title
4.2.4	— Fifth Supplemental Indenture, dated as of January 25, 2010, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Newfield's Current Report on Form 8-K filed with the SEC on January 25, 2010 (File No. 1-12534))
†10.1	— Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1 to Newfield's Registration Statement on Form S-8 (Registration No. 33-92182))
†10.1.1	— First Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
†10.1.2	— Second Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 to Newfield's Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
†10.2	— Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1.1 to Newfield's Registration Statement on Form S-8 (Registration No. 333-59383))
†10.2.1	— Amendment of 1998 Omnibus Stock Plan, dated May 7, 1998 (incorporated by reference to Exhibit 4.1.2 to Newfield's Registration Statement on Form S-8 (Registration No. 333-59383))
†10.2.2	— Second Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (as amended on May 7, 1998) (incorporated by reference to Exhibit 10.2 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
†10.2.3	— Third Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 99.2 to Newfield's Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
†10.3	— Newfield Exploration Company 2000 Omnibus Stock Plan (As Amended and Restated Effective February 14, 2002) (incorporated by reference to Exhibit 10.7.2 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
†10.3.1	— First Amendment to Newfield Exploration Company 2000 Omnibus Plan (As Amended and Restated Effective February 14, 2002) (incorporated by reference to Exhibit 10.3 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
†10.3.2	— Second Amendment to Newfield Exploration Company 2000 Omnibus Stock Plan (As Amended and Restated Effective February 14, 2002) (incorporated by reference to Exhibit 99.3 to Newfield's Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
†10.4	— Newfield Exploration Company 2004 Omnibus Stock Plan (As Amended and Restated Effective February 7, 2007) (incorporated by reference to Exhibit 10.1 to Newfield's Current Report on Form 8-K/A filed with the SEC on March 1, 2007 (File No. 1-12534))
†10.4.1	— First Amendment to Newfield Exploration Company 2004 Omnibus Stock Plan (As Amended and Restated Effective February 7, 2007) (incorporated by reference to Exhibit 10.4.1 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 1-12534))
†10.5	— Newfield Exploration Company 2007 Omnibus Stock Plan (incorporated by reference to Appendix A to Newfield's definitive proxy statement on Schedule 14A for its 2007 Annual Meeting of Stockholders filed with the SEC on March 16, 2007 (File No. 1-12534))
†10.5.1	— First Amendment to Newfield Exploration Company 2007 Omnibus Stock Plan (incorporated by reference to Exhibit 10.5.1 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 1-12534))
†10.6	— Newfield Exploration Company 2009 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 of Newfield's Registration Statement on Form S-8 (Registration No. 333-158961))
†10.7	— Form of TSR 2003 Restricted Stock Agreement between Newfield and each of David A. Trice, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell and James J. Metcalf dated as of February 12, 2003 (incorporated by reference to Exhibit 10.3.2 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))

Exhibit Number	Title
†10.8	— Form of TSR 2005 Restricted Stock Agreement between Newfield and each of David A. Trice, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Daryll T. Howard, Samuel E. Langford, Brian L. Rickmers and Susan G. Riggs dated as of February 8, 2005 (incorporated by reference to Exhibit 10.1 to Newfield's Current Report on Form 8-K filed with the SEC on February 11, 2005 (File No. 1-12534))
†10.9	— Form of TSR 2006 Restricted Stock Agreement between Newfield and each of Darryl T. Howard and Samuel E. Langford dated as of February 14, 2006 (incorporated by reference to Exhibit 10.1 to Newfield's Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
†10.10	— Form of TSR 2007 Restricted Stock Agreement between Newfield and each of David A. Trice, Michael Van Horn, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, John H. Jasek, Gary D. Packer and James T. Zernell dated as of February 14, 2007 (incorporated by reference to Exhibit 10.2 to Newfield's Current Report on Form 8-K filed with the SEC on February 21, 2007 (File No. 1-12534))
†10.11	— Form of 2007 Restricted Unit Agreement between Newfield and each of Michael Van Horn, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, John H. Jasek, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Brian L. Rickmers and Susan G. Riggs dated as of February 14, 2007 (incorporated by reference to Exhibit 10.3 to Newfield's Current Report on Form 8-K filed with the SEC on February 21, 2007 (File No. 1-12534))
†10.12	— Form of Restricted Stock Agreement between Newfield and (a) John Marziotti dated as of August 1, 2007 and (b) Lee K. Boothby and George T. Dunn dated as of October 1, 2007 (incorporated by reference to Exhibit 10.10 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
†10.13	— Form of 2008 Restricted Unit Agreement between Newfield and each of Lee K. Boothby, Michael Van Horn, Terry W. Rathert, William D. Schneider, George T. Dunn, Gary D. Packer, John H. Jasek, James T. Zernell, William Mark Blumenshine, Mona Leigh Bernhardt, Stephen C. Campbell, James J. Metcalf, John D. Marziotti, Brian L. Rickmers, Susan G. Riggs, Daryll T. Howard and Samuel E. Langford dated as of February 7, 2008 and William Mark Blumenshine dated as of March 15, 2008 (incorporated by reference to Exhibit 10.1 to Newfield's Current Report on Form 8-K filed with the SEC on February 14, 2008 (File No. 1-12534))
*†10.13.1	— Form of Amended and Restated 2008 Restricted Unit Agreement between Newfield and William D. Schneider effective as of February 7, 2008 (to make technical corrections only)
†10.14	— Form of 2008 Stock Option Agreement between Newfield and David A. Trice dated as of February 7, 2008 (incorporated by reference to Exhibit 10.2 to Newfield's Current Report on Form 8-K filed with the SEC on February 14, 2008 (File No. 1-12534))
†10.15	— Form of 2008 Stock Option Agreement between Newfield and each of Lee K. Boothby, Michael Van Horn, George T. Dunn, John H. Jasek, Gary D. Packer, James T. Zernell, William Mark Blumenshine, Mona Leigh Bernhardt, Stephen C. Campbell, John D. Marziotti, James J. Metcalf, Brian L. Rickmers, Susan G. Riggs, Daryll T. Howard and Samuel E. Langford dated as of February 7, 2008 (incorporated by reference to Exhibit 10.3 to Newfield's Current Report on Form 8-K filed with the SEC on February 14, 2008 (File No. 1-12534))
†10.16	— Form of Restricted Stock Agreement dated as of February 4, 2009 between Newfield and its executive officers (incorporated by referenced to Exhibit 10.15 to Newfield's Current Report on Form 8-K filed with the SEC on February 6, 2009 (File No. 1-12534))
†10.17	— Retirement Agreement between Newfield and David A. Trice dated as of April 20, 2009 (with Form of Restricted Stock Unit Agreement and Form of Non-Compete Agreement attached thereto) (incorporated by referenced to Exhibit 10.23 to Newfield's Current Report on Form 8-K filed with the SEC on April 22, 2009 (File No. 1-12534))
†10.18	— Form of Restricted Stock Agreement between Newfield and each of Lee K. Boothby and Gary D. Packer dated as of May 7, 2009 (incorporated by referenced to Exhibit 10.24 to Newfield's Current Report on Form 8-K filed with the SEC on May 11, 2009 (File No. 1-12534))

Exhibit Number	Title
†10.19	— Form of Restricted Stock Agreement between Newfield and each of Daryll T. Howard and Samuel E. Langford dated as of May 7, 2009 (incorporated by referenced to Exhibit 10.27 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2009 (File No. 1-12534))
*†10.20	— Form of 2010 TSR Restricted Stock Unit Agreement between Newfield and its executive officers dated as of February 4, 2010
*†10.21	— Form of 2010 Restricted Stock Unit Agreement between Newfield and its executive officers dated as of February 4, 2010
†10.22	— Newfield Exploration Company 2009 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 99.2 to Newfield's Registration Statement on Form S-8 (Registration No. 333-158961) (File No. 1-12534))
*†10.23	— Summary of Non-Employee Director Compensation Program
†10.24	— Second Amended and Restated Newfield Exploration Company 2003 Incentive Compensation Plan (incorporated by reference to Exhibit 10.2 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
†10.25	— Newfield Exploration Company Deferred Compensation Plan as Amended and Restated as of November 6, 2008 (incorporated by reference to Exhibit 10.17.1 to Newfield's Current Report on Form 8-K filed with the SEC on November 10, 2008 (File No. 1-12534))
†10.26	— Second Amended and Restated Newfield Exploration Company Change of Control Severance Plan (incorporated by reference to Exhibit 10.4 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
†10.27	— Form of Second Amended and Restated Change of Control Severance Agreement between Newfield and Terry W. Rathert dated effective as of July 26, 2007 (incorporated by reference to Exhibit 10.5 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
†10.28	— Form of Second Amended and Restated Change of Control Severance Agreement between Newfield and William D. Schneider dated effective as of July 26, 2007 (incorporated by reference to Exhibit 10.8 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
†10.29	— Amended and Restated Change of Control Severance Agreement between Newfield and Michael Van Horn dated effective as of July 26, 2007 (incorporated by reference to Exhibit 10.6 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
†10.30	— Second Amended and Restated Change of Control Severance Agreement between Newfield and Lee K. Boothby dated effective as of July 26, 2007 (incorporated by reference to Exhibit 10.7 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
†10.31	— Form of Amended and Restated Change of Control Severance Agreement between Newfield and each of John H. Jasek and James T. Zernell dated effective as of July 26, 2007 (incorporated by reference to Exhibit 10.9 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
†10.32	— Form of Third Amended and Restated Change of Control Severance Agreement between Newfield and each of George T. Dunn and Gary D. Packer dated effective as of November 7, 2008 (incorporated by reference to Exhibit 10.19.6 to Newfield's Current Report on Form 8-K filed with the SEC on November 10, 2008 (File No. 1-12534))
†10.33	— Form of Indemnification Agreement between Newfield and each of its directors and executive officers (incorporated by reference to Exhibit 10.20 to Newfield's Current Report on Form 8-K filed with the SEC on February 6, 2009 (File No. 1-12534))
†10.34.1	— Resolution of Members Establishing the Preferences, Limitations and Relative Rights of Series "A" Preferred Shares of Newfield China, LDC dated May 14, 1997 (incorporated by reference to Exhibit 10.15 to Newfield's Registration Statement on Form S-3 (Registration No. 333-32587))

Exhibit Number	Title
†10.34.2	— Amendment to Resolution of Members Establishing the Preferences, Limitations and Relative Rights of Series "A" Preferred Shares of Newfield China, LDC effective as of September 12, 2007 (incorporated by reference to Exhibit 10.21.2 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 1-12534))
10.35	— Credit Agreement, dated as of June 22, 2007, among Newfield Exploration Company, the Lenders party thereto, and JP Morgan Chase Bank, N.A., as Administrative Agent and as Issuing Bank (incorporated by reference to Exhibit 10.11 to Newfield's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
*21.1	— List of Significant Subsidiaries
*23.1	— Consent of PricewaterhouseCoopers LLP
*24.1	— Power of Attorney
*31.1	— Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	— Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	— Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	— Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed or furnished herewith.

† Identifies management contracts and compensatory plans or arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 26th day of February, 2010.

NEWFIELD EXPLORATION COMPANY

By: /s/ LEE K. BOOTHBY
Lee K. Boothby
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated and on the 26th day of February, 2010.

Signature	Title
/s/ LEE K. BOOTHBY Lee K. Boothby	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ TERRY W. RATHERT Terry W. Rathert	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ BRIAN L. RICKMERS Brian L. Rickmers	Controller (Principal Accounting Officer)
/s/ PHILIP J. BURGUIERES* Philip J. Burguieres	Director
/s/ PAMELA J. GARDNER* Pamela J. Gardner	Director
/s/ DENNIS R. HENDRIX* Dennis R. Hendrix	Director
/s/ JOHN R. KEMP III* John R. Kemp III	Director
/s/ J. MICHAEL LACEY* J. Michael Lacey	Director
/s/ JOSEPH H. NETHERLAND* Joseph H. Netherland	Director
/s/ HOWARD H. NEWMAN* Howard H. Newman	Director

Signature	Title
/s/ THOMAS G. RICKS* Thomas G. Ricks	Director
/s/ JUANITA F. ROMANS* Juanita F. Romans	Director
/s/ C. E. SHULTZ* C. E. Shultz	Director
/s/ J. TERRY STRANGE* J. Terry Strange	Director
/s/ DAVID A. TRICE* David A. Trice	Director (Chairman of the Board)

*By: /s/ BRIAN L. RICKMERS
Brian L. Rickmers,
as Attorney-in-Fact

Board of Directors

Lee K. Boothby (48)
President and Chief Executive Officer,
Newfield Exploration Company

Philip J. Burguieres (*) (***) (66)
Chairman and Chief Executive Officer,
EMC Holdings, LLC; Vice Chairman,
Houston Texans

Pamela J. Gardner (*) (***) (53)
President, Business Operations,
Houston McLane Company
d/b/a Houston Astros Baseball Club

Dennis R. Hendrix (**) (70)
Retired Chairman, PanEnergy Corp.

John Randolph Kemp III (*) (***) (65)
Principal, The Kemp Company, and
Retired President, Exploration Production,
Americas, Conoco, Inc.

J. Michael Lacey (**) (***) (64)
Retired Senior Vice President – Exploration
and Production, Devon Energy Corporation

Joseph H. Netherland (*) (***) (63)
Retired Chairman, President and Chief
Executive Officer, FMC Technologies, Inc.

Howard H. Newman (*) (62)
President and Chief Executive Officer,
Pine Brook Road Partners, LLC (Former
Vice Chairman, Warburg Pincus LLC)

Thomas G. Ricks (**) (***) (56)
Chief Investment Officer,
H&S Ventures L.L.C.

Juanita F. Romans (**) (***) (59)
Chief Executive Officer and Central
Market Leader, Memorial Hermann –
Texas Medical Center

C.E. (Chuck) Shultz (**) (70)
Chairman and Chief Executive Officer,
Dauntless Energy Inc.

J. Terry Strange (**) (***) (66)
Retired Vice Chairman, KPMG, LLP

David A. Trice (61)
Non-Executive Chairman of the Board;
Retired President and Chief Executive
Officer, Newfield Exploration Company

(*) Member of the Compensation and Management Development Committee

(**) Member of the Audit Committee

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

Executive Officers

Lee K. Boothby (48)
President and Chief Executive Officer
and Director

Gary D. Packer (47)
Executive Vice President and
Chief Operating Officer

Terry W. Rathert (57)
Executive Vice President and
Chief Financial Officer

Mona Leigh Bernhardt (43)
Vice President – Human Resources

W. Mark Blumenshine (51)
Vice President – Land

Stephen C. Campbell (41)
Vice President – Investor Relations

George T. Dunn (52)
Vice President – Mid-Continent

Daryll T. Howard (47)
Vice President – Rocky Mountains

John H. Jasek (40)
Vice President – Gulf of Mexico

Samuel E. Langford (52)
Vice President – Corporate Development

John D. Marziotti (46)
General Counsel and Secretary

James J. Metcalf (52)
Vice President – Drilling

Brian L. Rickmers (41)
Controller and Assistant Secretary

Susan G. Riggs (52)
Treasurer

William D. Schneider (58)
Vice President – Onshore Gulf Coast
and International

Michael D. Van Horn (58)
Vice President – Geoscience

James T. Zernell (52)
Vice President – Production

Office Locations

Newfield Exploration Company
363 North Sam Houston Parkway East
Suite 100
Houston, Texas 77060
Ph: 281-847-6000
Fax: 281-405-4242

Newfield Exploration Mid-Continent Inc.
One Williams Center, Suite 1900
Tulsa, Oklahoma 74172
Ph: 918-582-2690
Fax: 918-582-2757

Newfield Rocky Mountains Inc.
1001 Seventeenth Street, 20th Floor
Denver, Colorado 80202
Ph: 303-893-0102
Fax: 303-893-0103

Newfield Sarawak Malaysia Inc.
Newfield Peninsula Malaysia Inc.
Level 53, Tower 2, Petronas Twin Towers
Kuala Lumpar City Centre
50088 Kuala Lumpur
Ph: + (603) 2090 1888
Fax: + (603) 2382 6003

Newfield China LDC
Fortune Plaza, Suite 3703
No. 7 Dongsanhuan Zhong Road
Chaoyang District, Beijing 100020
P.R. China
Ph: + 86 (10) 6530 9788
Fax: + 86 (10) 6530 9009

NEWFIELD

2010 Priorities

- Grow 2010 production 8-12% over 2009.
- Focus on large, domestic resource plays of scale.
- Increase investments in oil plays.
- Develop in-hand fields in the deepwater Gulf of Mexico and Southeast Asia.
- Continue to harvest assets and re-invest cash flow into higher return opportunities.
- Maintain a strong balance sheet and ample liquidity.
- Continued improvements in capital allocation.

2010 Capital Allocation

- Our 2010 budget is $1.6 billion.
- More than 70% of the 2010 capital budget is allocated to resource plays, primarily in the Mid-Continent and the Rocky Mountains.
- Approximately 70% of our expected 2010 natural gas production and 40% of our expected oil production is hedged.

2009 Newfield Accomplishments

- Revenues for 2009 were $1.3 billion.
- Improved resource and capital allocation in 2009. Investments were within cash flow while reducing debt by about $200 million.
- Our 2009 production was 257 Bcfe, an increase of 9% over 2008 production.
- 2009 proved reserves increased 23% over prior year to 3.6 Tcfe. Proved reserves in our two largest regions – the Mid-Continent and Rocky Mountains – increased 34% and represent more than 80% of our total proved reserves.
- Since mid-2009, Newfield added more than 500,000 net acres in long lived, domestic resource plays - the Maverick Basin (Eagle Ford and Pearsall Shales), the Marcellus Shale and the Southern Alberta Basin.
- Our two largest regions: The Mid-Continent and the Rocky Mountains grew net production 18% and 10%, respectively.
- Exploration successes: Pyrenees, deepwater Gulf of Mexico; Pearl, offshore China.
- 2009 International oil production up 40% over 2008.

Profile

Newfield Exploration Company is an independent crude oil and natural gas exploration and production company. Our domestic areas of operation include the Anadarko and Arkoma Basins of the Mid-Continent region, multiple basins in the Rocky Mountains, onshore Texas and the Gulf of Mexico. The Company also has operations in Malaysia and China.

Our Business Principles

- Grow reserves through the drilling of a balanced risk/reward portfolio and select acquisitions
- Focus on select geographic areas
- Control operations and costs
- Attract and retain a quality workforce through equity ownership and other performance-based incentives

Annual Meeting

Our Annual Meeting will be held at 8 a.m., May 7, 2010, 19th Floor Front Range Room of the Company's Rocky Mountains office located at:
1001 Seventeenth Street
Denver, Colorado 80202

Stock Information

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

Transfer Agent

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

Information

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

Corporate Headquarters

Newfield Exploration Company
363 North Sam Houston Parkway East
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