NEWFIELD EXPLORATION CO /DE/
Form 10-K
February 27, 2009

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

Form 10-K

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2008**
	or
o	**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 þ No o

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. þ

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $8.5 billion as of June 30, 2008 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 23, 2009, there were 132,794,710 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, 2009, which is incorporated by reference to the extent specified in Part III of this Form 10-K.

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If you are not familiar with any of the oil and gas terms used in this report, we have provided explanations of many of them under the caption Commonly Used Oil and Gas Terms at the end of Item 7 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. This report contains information that is forward-looking or relates to anticipated future events or results. See Forward-Looking Information.

PART I

Item 1. *Business*

We are an independent oil and gas company engaged in the exploration, development and acquisition of natural gas and crude oil 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. 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 at our website is not incorporated by reference into this report and you should not consider information contained at our website as part of this report.

Overview

We are a Delaware corporation and were founded in 1989. For the first 10 years of our existence, we focused almost exclusively on the shallow waters of the Gulf of Mexico. In the late 1990s, our operations expanded to other regions. This broadened scope allowed us to gain access to properties and opportunities necessary for continued growth. Today, 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; a large inventory of low risk exploitation and development opportunities; and a smaller, but significant, inventory of higher risk, higher reserve potential exploration opportunities.

At year-end 2008, we had proved reserves of 2.95 Tcfe. Those reserves were 72% natural gas and 62% proved developed. As a result of our increasing investments in unconventional resource plays in the Mid-Continent and Rocky Mountains and the sale of our shallow water Gulf of Mexico assets in 2007, our reserve life index is now more than 12.5 years.

2008 Proved Reserves by Area	2009 Estimated Production by Area
2.95 TCFE	250 260 BCFE

2009 Outlook and Capital Investments

Both oil and gas prices declined rapidly in the second half of 2008. In addition, capital markets are constrained due to global financial and economic conditions. The confluence of these events led us to make some changes in our planned activities and spending levels for 2009. Our diversified portfolio of assets

provides us with flexibility in our capital allocation process. We have reduced our original spending plans for 2009 by nearly 30% and expect that our investment levels will match our total 2009 cash flows from operations. Our cash flow assumptions for 2009 assume a positive benefit from our hedging position. For a complete discussion of our hedging activities, a listing of open contracts as of December 31, 2008 and the estimated fair value of these contracts as of that date, see Note 5, Commodity Derivative Instruments, to our consolidated financial statements.

Our capital investment plan in 2009 preserves available liquidity, ensures our leverage ratios remain at what we consider to be acceptable levels and provides for the ongoing development of our largest assets. With the expectation that commodity prices could remain low throughout 2009, we reduced our investment levels in basins where oil and gas prices are typically weaker due to the distance from consuming markets and resulting price basis differentials. As an example, we have reduced our gas drilling plans in the Rocky Mountains and allocated more to the Mid-Continent where firm transportation agreements ensure higher realized prices. In our two largest development areas the Woodford Shale and Monument Butte substantially all of our acreage is held by production, which means that a reduction in our activity levels in those areas will not result in lost opportunities. We also have sold down our interest or taken partners who have agreed to pay a disproportionate share of costs in areas like the deepwater Gulf of Mexico to both reduce our risks and stretch our capital investments. In South Texas, we have significantly reduced our planned exploration expenditures due to project economics at lower commodity prices. In Malaysia, we also were able to defer some of our planned activities and investments into 2010.

Our 2009 capital budget is $1.45 billion, including approximately $130 million of estimated capitalized interest and overhead. We expect our 2009 production to grow 6-10% over 2008 levels. Our planned capital investments include funding projects that will lead to future growth. At our planned level of investments in 2009, we expect to have comparable production growth in 2010. We have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations.

Please see the discussion under *We have substantial capital requirements to fund our business plans, and the current poor conditions generally in the economy and in the financial markets could jeopardize our ability to execute our business plans* and the other disclosures in Item 1A of this report.

Resource Plays

At year-end 2008 approximately 65% of our proved reserves were in resource plays. As the traditional producing basins in the U.S. have matured, exploration and production has shifted to unconventional resource plays. Resource plays typically cover expansive areas, provide multi-year inventories of drilling opportunities and have sustainable lower risk growth profiles. The economics of these plays have been enhanced by continued advancements in drilling and completion technologies. These advancements make resource plays resilient to lower commodity prices. Today, we have two large resource plays the Woodford Shale in the Arkoma Basin of southeast Oklahoma and Monument Butte in northeast Utah.

Woodford Shale. Our largest single investment area over the last three years has been the Woodford Shale. Our activities began in this area in 2003. At year-end 2008, we owned an interest in approximately 165,000 net acres. Our average working interest is approximately 60%. Since 2003, we have drilled more than 100 vertical wells and 245 horizontal wells. The Woodford is a shale formation that varies in thickness from 100 200 feet throughout our acreage. Our 2008 production was 65% higher than in 2007 and at year-end 2008 was approximately 250 MMcfe/d (gross). Full development of the play will require several thousand wells. Our development program consists of drilling wells on 40 acre spacing and we are drilling an increasing number of horizontal wells with longer lateral completions. A long lateral completion is defined as a horizontal section in the Woodford up to 10,000 feet in length. About 80% of our planned wells in 2009 will be drilled from common surface locations or pads, reducing both costs and our impact on the environment.

Monument Butte. Our largest asset in the Rocky Mountains is the Monument Butte oil field, located in the Uinta Basin of Utah. The field accounts for approximately 20% of our year-end 2008 proved reserves and encompasses about 184,000 gross acres, including nearly 45,500 net acres added through two ventures with Ute Energy LLC. Our working interest in the field averages 86%. We operate the field and control the timing and pace of our operations. Since we purchased the Monument Butte field in 2004, we have drilled 916 wells and have thousands of remaining infill drilling locations. At year-end 2008, the field had 1,273 productive oil wells and gross daily production of more than 16,500 BOPD.

Our activity levels and production growth in the field are set in accordance with demand for our black wax crude from refiners in the Salt Lake City, Utah area and our ability to obtain drilling permits in a timely manner. About half of our Monument Butte production at year-end 2008 was being sold under firm contracts. Area refiners have added new refining capacity over the past months and we expect that demand for our black wax crude oil will increase. However, in the current economic and capital market environments, there is an increased risk that purchasers of our black wax crude production may fail to satisfy their obligations to us under those contracts. We are working to secure additional long-term agreements with refiners. Please see the discussion under *There is limited refining capacity for our black wax crude oil, and our ability to sell our current production or to increase our production at Monument Butte may be limited by the demand for our crude oil production* in Item 1A of this report.

Granite Wash. In addition to the Woodford Shale, we are also active in the Granite Wash play (also known as Mountain Front Wash), located in the Anadarko Basin. We drilled our first horizontal well in the Granite Wash in late 2008 and plan several more. We believe that we have 90-100 remaining horizontal drilling locations in the Granite Wash. Our production in the play reached 130 MMcfe/d (gross) in early 2009, a record level. Our largest producing field in the play is Stiles Ranch, where our working interest is predominately 100%.

Williston Basin. We have a growing position in the Williston Basin and at year-end 2008 had an interest in approximately 470,000 net acres. Our drilling successes in 2008 increased our net production to approximately 2,500 BOPD in mid-February 2009. Targeted geologic formations in the basin include the Three Forks/Sanish, Bakken, Madison, Red River and Duperow.

Green River Basin. We own interests in 8,000 gross acres (4,000 net acres) in the Pinedale Field, located in Sublette County, Wyoming. We see the potential to drill approximately 120 additional locations as field spacing is decreased to 20 acres and eventually to 10 acres. We 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.

Conventional Plays

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

Onshore Texas. We are active in South Texas, the Val Verde Basin of West Texas and in East Texas. We have a presence in most of the major producing trends in onshore Texas and our gross production was approximately 225 MMcfe/d at year-end 2008. Our drilling program over the last several years has focused on the Wilcox, Vicksburg and Frio plays in South Texas. In these trends, we have an interest in more than 60,000 gross acres primarily in Kenedy, Hidalgo, Brooks and Zapata Counties, including two joint ventures with ExxonMobil. In East Texas, we have an interest in 36,000 net acres.

We have interests in nearly 130,000 gross acres in the Val Verde Basin where prospective drilling targets include the Canyon, Strawn and Ellenberger formations. Our production from the area was approximately 50 MMcfe/d (gross) at year-end 2008 and our working interests range from 50% to 100%.

Gulf of Mexico. We remain active in the Gulf of Mexico and have growing operations in the deepwater. At year-end 2008, our daily production capacity from the Gulf of Mexico was approximately 50 MMcfe/d (net), which includes about 25 MMcfe/d (net) shut-in due to hurricane repairs. As of December 31, 2008, we owned interests in 76 deepwater leases (approximately 438,000 gross acres) and 26 leases on the shelf.

We have five deepwater field developments underway that are expected to provide future production growth. We have an inventory of prospects acquired primarily through federal lease sales over the last two years. Our deepwater program provides us with significant reserve exposure and represents a substantial component of our

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ongoing exploration efforts. Our deepwater exploration efforts can be classified into two distinct categories prospects near existing infrastructure and those requiring stand-alone developments. The prospects located near existing infrastructure are generally smaller and lower risk than those requiring a stand-alone development. We prefer to operate prospects near existing infrastructure with interests ranging from 30 70%. Stand-alone developments are generally in water depths greater than 5,500 feet and have longer lead times for development. We often manage our exposure to these higher risk prospects by taking a smaller working interest or selling down our interest to others who have agreed to pay a disproportionate share of drilling costs.

We make selective investments in the shallow water Gulf of Mexico to take advantage of our regional expertise and 3-D seismic data base. We have made four discoveries since late 2007 that are expected to add to our production volumes in 2009 and 2010.

International. We are active offshore Malaysia and China. Our international production at year-end 2008 was 17,500 BOPD (net), an increase of 175% over 2007. The increase was related primarily to new field developments in Malaysia that commenced production in 2008.

Our activities in Malaysia began in 2004 and in early 2009 we had production of approximately 43,000 BOPD (gross) from seven shallow water oil developments. Our Malaysian concessions include a 50% non-operated interest in PM 318 (435,000 gross acres) and a 60% operated interest in PM 323 (353,000 gross acres). On PM 318, our Abu field commenced production in 2007 and production at year-end 2008 was approximately 14,000 BOPD (gross). Our Puteri field commenced production in the third quarter of 2008 and has the capacity to produce 6,000 8,000 BOPD (gross). On PM 323, first production commenced from our East Belumut and Chermingat fields in the third quarter of 2008 and had gross production of about 15,000 BOPD at year-end 2008. In 2008, we signed two new production sharing contracts on shallow water Block SK 310 (1.1 million gross acres) and PM 329 (96,000 gross acres).

We also have interests in deepwater Block 2C offshore Sarawak (1.1 million acres). As of mid-February 2009, we were in the process of drilling a high-risk high-potential deepwater prospect on Block 2C. This is our second of two required commitment wells on this block. We operate the exploratory well with a 40% interest.

In Bohai Bay, China, we have production of 1,800 BOPD (net) through our outside operated interests. We also have three offshore exploration concessions in the South China Sea that cover approximately 3.5 million gross acres. We made an oil discovery on this acreage in 2008 that will require additional drilling to determine its commerciality.

For revenues from and income taxes related to our domestic and international operations, see Note 15, Segment Information, and Note 10, Income Taxes, to our consolidated financial statements appearing later in this report.

Strategy

The elements of our growth strategy have remained substantially unchanged since our founding and consist of:

- growing reserves through an active drilling program and select acquisitions;
- focusing on select geographic areas;
- controlling operations and costs; and
- attracting and retaining a quality workforce through equity ownership and other performance-based incentives.

Drilling Program. The components of our drilling program reflect the significant changes in our asset base over the last few years. An increasing portion of our drilling budget is being allocated to our longer-lived resource plays. Due to our capital allocation plans in 2009, the majority of our wells will be lower risk development wells in our Mid-Continent and Rocky Mountain regions.

Acquisitions. Acquisitions have consistently been a part of our strategy, particularly when entering new geographic regions. Since 2000, we have completed four significant acquisitions that led to the establishment of focus areas onshore U.S. We will continue to screen for value-adding acquisitions.

Geographic Focus. We believe that our long-term success requires extensive knowledge of the geologic and operating conditions in the areas where we operate. Therefore, we focus our efforts on a limited number of geographic areas where 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 2008, we operated about 80% of our total net 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 significant portion of our employees compensation is tied to profitability. As of February 23, 2009, our employees owned or had options to acquire at least 5% of our outstanding common stock on a diluted basis.

Our Properties and Plans for 2009

Our largest investment regions in 2009 will be the Mid-Continent and the Rocky Mountains. Approximately 43% of the budget is allocated to the Mid-Continent, 17% to the Rocky Mountains, 18% to the Gulf of Mexico, 14% to onshore Texas and 8% to international projects. Our most significant investment projects are detailed below.

Mid-Continent. Our activities in the Mid-Continent are focused primarily in the Anadarko and Arkoma Basins. As of December 31, 2008, we owned a working interest in more than 750,000 gross acres and approximately 2,000 gross producing wells. This region is characterized by longer-lived natural gas production. For 2009, we plan to invest about $610 million in the Mid-Continent to operate the drilling of about 100 wells.

We plan to invest approximately $450 million of the total Mid-Continent capital budget in the Woodford Shale in 2009. We expect to drill about 80 operated horizontal wells by running 11 rigs throughout the year. Throughout 2008, we increased the length of our lateral completions, adding improved gas recoveries, higher production rates and better overall economics. Although we will run one less rig in 2009 than in 2008, we expect to drill and complete an additional 100,000 feet of Woodford section. Simply stated, we are drilling our wells faster and more efficiently. We expect that the average length of our lateral completions in 2009 will exceed 5,000 feet and that 75% of our planned wells will be drilled from common surface locations or pads. In addition, we also will participate in the drilling of 60 70 wells operated by others in this area.

We plan to operate one or two drilling rigs in our Granite Wash play. We recently drilled our first horizontal well in this play and are encouraged by the initial results. We are planning to drill about 10 additional horizontal wells in the field in 2009 and invest $60 $70 million.

Rocky Mountains. As of December 31, 2008, we owned an interest in about 1.2 million gross acres and approximately 1,950 gross producing wells. Our assets in the Rockies are nearly 70% oil and have long-lived production. In 2007, we acquired the Rocky Mountain assets of Stone Energy for $578 million, adding 200 Bcfe of proved reserves and exposure to new basins.

We plan to run a three-rig drilling program in 2009 and expect to drill about 150 wells at Monument Butte. This is a 100 well reduction from our 2008 drilling and reflects a reduced capital investment in this long-lived oil field.

Because this field is held-by-production, our reduced activity levels will not result in lost opportunities. Our program will focus on continued development of the field on 40 and 20 acre locations. We have an estimated 1,000 locations remaining to drill the field down to 40-acre spacing. We have drilled 128 wells on 20-acre spacing and results indicate that a large portion of the field will be developed on 20-acre spacing. We have an estimated additional 1,000 2,500 locations remaining to drill the field down to 20-acre spacing. We will continue to invest on the 45,500 net acres north and adjacent to the Monument Butte field that we have interests in with Ute Energy LLC. As of mid-February 2009, we had drilled more than 45 wells on this acreage and results are consistent with those from our main field.

There is a significant gas resource beneath the shallow producing oil zones at Monument Butte. In 2008, we participated in the drilling of six deep tests to evaluate these gas-bearing formations the Wasatch, Mesa Verde, Blackhawk, Mancos and Dakota. We were encouraged by our results and believe that the deep gas play will be commercial at higher natural gas prices. We have deferred additional drilling expenditures in the play in 2009 and will study our recently collected data. Our collection of data in 2008 was aided by a deep gas agreement that we signed with Red Technology Alliance. The agreement allowed for promoted exploratory drilling and progressive earning in approximately 71,000 net acres in which we retain a majority interest. Three of the wells we drilled in 2008 were under this agreement. Red Technology Alliance plans to drill several additional wells in this area in 2009 to further define this resource. Approximately 10,000 net acres in the immediate vicinity of our recent deep gas tests were excluded from the agreement with Red Technology Alliance. We drilled three successful operated wells in this area in 2008.

We also have an active program in the Williston Basin. We will maintain a one-rig program in 2009 focused on drilling exploration wells to assess acreage for future development, as well as to drill wells to hold recently acquired acreage through production. To date, we have drilled nine successful wells with production from the Bakken and Three Forks/Sanish formations. During 2009, we expect to drill about 10-12 additional wells and invest about $45 million.

Gulf of Mexico. Our activities in the Gulf of Mexico are primarily focused on deepwater. Through bidding successes at recent lease sales, we established a large inventory of prospects in the deepwater Gulf of Mexico, which have a 10-year term. As of mid-February 2009, we were in the process of drilling the second of two planned exploration wells. We have five deepwater field developments underway that are expected to grow our production in 2009 through 2012.

Onshore Texas. As of December 31, 2008, we owned an interest in approximately 400,000 gross acres and about 1,000 gross producing wells onshore Texas. We expect to drill 25 30 wells in this region in 2009.

International. Our international activities are focused offshore Malaysia and China. We plan to invest $95 million in 2009, which includes one deepwater exploratory well in Malaysia and continued development drilling in our shallow water oil fields.

Marketing

Substantially all of our natural gas and oil 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, and our ability to sell our current production or to increase our production at Monument Butte may be limited by the demand for our crude oil production* 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 23, 2009, we had 1,054 employees. All but 95 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

For a discussion of the significant governmental regulations to which our business is subject, please see the information set forth under the caption Regulation in Item 7 of this report.

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 source of capital resources to fund capital expenditures, estimates of proved reserves and the estimated present value of such 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 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;
- 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;
- severe weather conditions (such as hurricanes); 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 Item 1. *Business*, 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.

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. These 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 amount that we may borrow under our credit facility is determined by our lenders annually each May (and may be redetermined 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 and natural gas;
- the price and availability of alternative fuels;
- disruptions in supply and changes in demand caused by weather conditions;
- changes in demand as a result of changes in price;
- the price of foreign imports;
- world-wide economic conditions;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations.

We have substantial capital requirements to fund our business plans, and the current poor conditions generally in the economy and in the financial markets could jeopardize our ability to execute our business plans. Although we have reduced our 2009 capital budget to a level that we believe corresponds with our anticipated 2009 cash flows, since the timing of capital expenditures and the receipt of cash flows do not necessarily match, we anticipate borrowing and repaying funds under our credit arrangements throughout the year. We may have to further reduce capital expenditures and our ability to execute our business plans could be diminished 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.

Global credit markets have been, and continue to be, distressed. In this environment, the cost of raising money in the financial markets has increased while the availability of funds from those markets has diminished. In the current environment, many lenders have increased rates, imposed tighter lending standards, refused to refinance existing debt at maturity or on similar terms to existing debt and have reduced or ceased to provide new funding.

In addition, to the extent that purchasers of our production or our working interest owners have difficulty financing their business activities, there could be an increased risk that purchasers of our production may default in their contractual obligations to us or that working interest owners may be unable or unwilling to pay their share of costs as they become due. Although we perform credit analyses on our customers, the general downturn in the economy and tightening of the financial markets could increase the risk that our customers and working interest owners fail to perform.

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 natural 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 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. Although the use of hedging transactions limits the downside risk of price declines, their use also may limit future revenues from price increases.

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 the current economic environment 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. We accomplish this through successful drilling programs and the acquisition of properties. However, we may be unable to find, develop or acquire additional reserves or production at an acceptable cost. In addition, these activities require substantial capital expenditures. Although we have reduced our 2009 capital budget to a level that we believe corresponds with our anticipated 2009 cash flows, we anticipate borrowing and repaying funds under our credit arrangements throughout the year to the extent that the timing of capital expenditures and the receipt of cash flows from operations do not match. We anticipate that any cash flow shortfall will be made up with cash on hand and borrowings under our credit arrangements. Lower oil and gas prices or unexpected operating constraints or production difficulties will decrease cash flow from operations and could limit our ability to borrow under our credit arrangements. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. Our ability to fund attractive acquisition opportunities and future capital programs may be dependent on our ability to access capital markets. Further or continued volatility in the credit markets could adversely impact our ability to obtain financing at all or on acceptable terms. Because all of our credit arrangements provide for variable interest rates, higher interest rates would also reduce cash flow. For a detailed discussion of our credit arrangements and liquidity, please see Liquidity and Capital Resources in Item 7 of this report and Note 9, Debt, to our consolidated financial statements in Item 8 of this report.

Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves most likely will 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 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 recoverable oil and gas reserves, future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from our estimates. Any significant variance could materially affect the quantities and net present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development activities and prevailing oil and gas prices. Our reserves also may be susceptible to drainage by operators on adjacent properties.

You should not assume that the present value of future net cash flows is the current market value of our proved oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices 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, and our ability to sell our current production or to increase our production at Monument Butte may be limited by the demand for our crude oil production. Most of the crude oil we produce in the Uinta Basin is known as black wax because it has

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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 two area refiners that secure base load sales of approximately 5,000 BOPD through the end of 2009. In the current economic environment and tight financial markets, there is an increased 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. 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 resulted in a ceiling test writedown 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, using period-end oil and gas prices and a 10% discount factor, plus the lower of cost or fair market value for unproved properties. 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. 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.

We review the net capitalized costs of our properties quarterly, based on prices in effect (excluding the effect of our hedging contracts that are not designated for hedge accounting) as of the end of each quarter or as of the time of reporting our results. The net capitalized costs of oil and gas properties are computed on a country-by-country basis. Therefore, while our properties in one country may be subject to a writedown, our properties in other countries could be unaffected. We also assess investments in unproved properties periodically to determine whether impairment has occurred.

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:

- shortages or delays in the availability of drilling rigs and the delivery of equipment;
- adverse weather conditions;
- unexpected drilling conditions;
- pressure or irregularities in formations;

embedded oilfield drilling and service tools;

equipment failures or accidents; and

compliance with governmental requirements.

The oil and gas business involves many operating risks that can cause substantial losses; insurance may not protect us against all of these risks. These risks include:

- 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; and
- build up of naturally occurring radioactive materials.

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 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 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 require substantial capital investment. Because of their size, we may not serve as the operator of significant projects in which we invest. 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.

In addition, there is limited availability of suitable drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel, and deepwater drilling rigs typically are subject to long-term contracts. This can lead to difficulty and delays in consistently obtaining drilling rigs and other equipment and services at acceptable rates, which, in turn, may lead to projects being delayed or increased costs. This also makes it difficult to estimate the timing of our production.

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.

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

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

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

We are subject to complex laws that can affect the cost, manner or feasibility of doing 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. Moreover, these laws could change in ways that substantially increase our costs. 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.

Potential regulations regarding climate change could alter the way we conduct our business. Governments around the world are beginning to address climate change matters. This may result in new environmental regulations that may unfavorably impact us, our suppliers and our customers. The cost of meeting these requirements may have an adverse impact on 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;
- renegotiation of contracts with governmental entities and quasi-governmental agencies;
- changes in laws and policies governing operations of non-U.S. based companies;
- labor problems; 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.

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.

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Item 2. *Properties*

The information appearing in Item 1 of this Annual Report is incorporated herein by reference.

Concentration

At year end 2008, 94% of our proved reserves were located in the U.S. and 89% were located onshore. Our 10 largest fields or plays accounted for approximately 79% of our proved reserves at year-end 2008. The largest of those, the Woodford Shale play and the Monument Butte field, accounted for about 48% of our proved reserves and around 33% of the net present value of our proved reserves at December 31, 2008.

Proved Reserves and Future Net Cash Flows

The following table shows our estimated net proved oil and gas reserves and the present value of estimated future after-tax net cash flows related to those reserves as of December 31, 2008.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Domestic:			
Oil and condensate (MMBbls)	65	46	111
Gas (Bcf)	1,336	774	2,110
Total proved reserves (Bcfe)	1,727	1,047	2,774
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 2,545
International:			
Oil and condensate (MMBbls)	17	12	29
Gas (Bcf)			
Total proved reserves (Bcfe)	100	76	176
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 384
Total:			
Oil and condensate (MMBbls)	82	58	140
Gas (Bcf)	1,336	774	2,110
Total proved reserves (Bcfe)	1,827	1,123	2,950
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 2,929

(1) This measure was prepared using year-end oil and gas prices applicable to our reserves and cash flows discounted at 10% per year. Weighted average year-end prices were $4.76 per Mcf for gas and $33.65 per Bbl for oil. This calculation does not include the effects of hedging. For a further description of how this measure is determined, please see Supplementary Financial Information Supplementary Oil and Gas Disclosures Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves in Item 8 of this report.

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. Actual quantities of recoverable reserves and future cash flows from those reserves most likely will vary from the estimates set forth above. Reserve and cash flow estimates rely on interpretations of data and require many assumptions that may turn out to be inaccurate. For a discussion of these interpretations and assumptions, see *Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves most likely will vary from our estimates* under Item 1A of this report.

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, 2008.

	2008		2007		2006	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory wells:						
Domestic:						
Productive(1)	385	217.4	343	219.0	420	290.5
Nonproductive(2)	20	15.4	24	16.6	36	21.1
International:						
China:						
Productive(3)	2	1.1				
Nonproductive(4)	1	1.0				
Malaysia:						
Productive(5)	5	2.6	1	0.6	10	4.9
Nonproductive(6)			3	2.1	3	1.6
International Total:						
Productive	7	3.7	1	0.6	10	4.9
Nonproductive	1	1.0	3	2.1	3	1.6
Exploratory well total	413	237.5	371	238.3	469	318.1
Development wells:						
Domestic:						
Productive	175	138.2	135	105.7	199	183.2
Nonproductive	4	3.0	2	1.6	3	2.7
International:						
China:						
Productive	6	0.7	8	1.0	14	1.7
Nonproductive	2	0.2				
Malaysia:						
Productive	7	4.2	3	1.7		
Nonproductive						
International Total:						
Productive	13	4.9	11	2.7	14	1.7
Nonproductive	2	0.2				
Development well total	194	146.3	148	110.0	216	187.6

(1) Includes 38 gross (27.1 net), 19 gross (12 net) and 62 gross (52.6 net) wells in 2008, 2007 and 2006, respectively, that are not exploitation wells.

(2) Includes 9 gross (7.5 net), 15 gross (8.8 net) and 16 gross (10.8 net) wells in 2008, 2007 and 2006, respectively, that are not exploitation wells.

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

(4) This well was not an exploitation well.

(5) Includes 2 gross (1.1 net) and 2 gross (0.9 net) wells in 2008 and 2006, respectively, that are not exploitation wells.

(6) Includes 3 gross (2.1 net) and 2 gross (1.1 net) wells in 2007 and 2006, respectively, that are not exploitation wells.

We were in the process of drilling 58 gross (34.1 net) exploratory wells (includes 57 gross (33.1 net) exploitation wells) and six gross (4.9 net) development wells in the United States at December 31, 2008. There were no wells being drilled internationally at December 31, 2008.

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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, 2008 and the location of, and other information with respect to, those wells.

	Company Operated Wells		Outside Operated Wells		Total Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
Domestic:						
Gulf of Mexico:						
Oil			2	0.5	2	0.5
Gas	2	1.3	2	0.6	4	1.9
Montana:						
Oil	72	57.3	36	8.1	108	65.4
Gas						
North Dakota:						
Oil	24	15.2	55	4.3	79	19.5
Gas			1		1	
Oklahoma:						
Oil	294	215.0	51	6.0	345	221.0
Gas	695	520.6	688	114.6	1,383	635.2
Texas:						
Oil	28	23.4	16	5.4	44	28.8
Gas	645	575.6	301	119.5	946	695.1
Utah:						
Oil	1,309	1,074.1	15	3.5	1,324	1,077.6
Gas	16	11.0	1	0.1	17	11.1
Wyoming:						
Oil	100	89.0	14	3.1	114	92.1
Gas	49	29.4	44	9.7	93	39.1
Other domestic:						
Oil	1	0.7			1	0.7
Gas	11	6.6	22	5.3	33	11.9
Total domestic:						
Oil	1,828	1,474.7	189	30.9	2,017	1,505.6
Gas	1,418	1,144.5	1,059	249.8	2,477	1,394.3
International:						
Offshore China:						
Oil			30	3.6	30	3.6
Offshore Malaysia:						
Oil	9	5.4	22	11.0	31	16.4
Total international:						

Oil	9	5.4	52	14.6	61	20.0
Total:						
Oil	1,837	1,480.1	241	45.5	2,078	1,525.6
Gas	1,418	1,144.5	1,059	249.8	2,477	1,394.3
Total	3,255	2,624.6	1,300	295.3	4,555	2,919.9

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, 2008, we owned interests in developed and undeveloped oil and gas acreage in the locations 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:				
Gulf of Mexico:				
Deepwater	75	16	363	226
Shelf	13	1	96	65
Treasure Project			294	37
Total Gulf of Mexico	88	17	753	328
Onshore:				
Colorado			78	38
Montana	31	24	430	335
Nevada			91	91
North Dakota	14	6	180	103
Oklahoma	528	302	203	59
Texas	170	109	231	148
Utah	68	56	245	190
Wyoming	17	12	140	78
Other domestic	21	10	2	
Total onshore	849	519	1,600	1,042
Total domestic	937	536	2,353	1,370
International:				
Offshore Brazil			121	121
Offshore China	22	3	3,558	3,558
Offshore Malaysia	114	58	2,939	1,197
Total international	136	61	6,618	4,876
Total	1,073	597	8,971	6,246

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 363,402 gross (108,111 net) undeveloped acres. These interests do not expire.

	Undeveloped Acres Expiring (In thousands)									
	2009		2010		2011		2012		2013	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Domestic:										
Gulf of Mexico:										
Deepwater	6	4	23	9	17	13	52	11	75	54
Shelf	15	7	15	8	6	6	5	5	33	33
Treasure Project	57	6	41	5	5	1				
Total Gulf of Mexico	78	17	79	22	28	20	57	16	108	87
Onshore:										
Colorado	48	9	20	15	6	2				
Montana	26	6	348	201	147	73	21	7		
North Dakota	50	16	45	15	93	56	12	7	2	1
Oklahoma	46	21	66	30	15	7				
Texas	66	49	84	48	29	17	10	8	1	1
Utah	12	8	32	27	11	9	24	20	3	3
Other domestic	3	2	16	16	12	10	1	1	1	
Total onshore	251	111	611	352	313	174	68	43	7	5
Total domestic	329	128	690	374	341	194	125	59	115	92
International:										
Offshore China	2,266	2,266	1,292	1,292						
Offshore Malaysia	336	168	338	203	1,079	431			1,187	395
Total international	2,602	2,434	1,630	1,495	1,079	431			1,187	395
Total	2,931	2,562	2,320	1,869	1,420	625	125	59	1,302	487

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 crude oil and natural 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.

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

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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 2008.

Executive Officers of the Registrant

The following table sets forth the names and ages (as of February 23, 2009) 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
David A. Trice	60	Chairman and Chief Executive Officer and a Director	14
Lee K. Boothby	47	President	9
Terry W. Rathert	56	Senior Vice President and Chief Financial Officer	19
Michael D. Van Horn	57	Senior Vice President Exploration	2
Mona Leigh Bernhardt	42	Vice President Human Resources	9
W. Mark Blumenshine	50	Vice President Land	7
Stephen C. Campbell	40	Vice President Investor Relations	9
George T. Dunn	51	Vice President Mid-Continent	16
John H. Jasek	39	Vice President Gulf of Mexico	9
James J. Metcalf	51	Vice President Drilling	13
Gary D. Packer	46	Vice President Rocky Mountains	13
William D. Schneider	57	Vice President Onshore Gulf Coast and International	20
Mark J. Spicer	49	Vice President Information Technology	8
James T. Zernell	51	Vice President Production	11
John D. Marziotti	45	General Counsel and Secretary	5
Brian L. Rickmers	40	Controller and Assistant Secretary	15
Susan G. Riggs	51	Treasurer	11

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

David A. Trice was appointed Chairman of the Board of our company in September 2004. From October 2007 to February 5, 2009, Mr. Trice also served as President of our company. Mr. Trice announced that he will retire as our Chief Executive Officer at the annual meeting of our stockholders on May 7, 2009.

Lee K. Boothby was promoted to his present position on February 5, 2009. Our Board of Directors has announced that it expects to name Mr. Boothby to the additional role of Chief Executive Officer effective at the annual meeting on May 7, 2009. 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.

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

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

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.

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.

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

Gary D. Packer was promoted from Gulf of Mexico General Manager to Vice President Rocky Mountains in November 2004. Our Board of Directors has announced that it expects to promote Mr. Packer to the position of Executive Vice President and Chief Operating Officer effective at the annual meeting of our stockholders on May 7, 2009.

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

Mark J. Spicer was promoted from Manager to Vice President in December 2005.

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.

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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
2007		
First Quarter	$ 45.36	$ 39.30
Second Quarter	54.28	41.15
Third Quarter	58.08	41.82
Fourth Quarter	55.00	46.98
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 (through February 23, 2009)	$ 24.29	$ 17.43

On February 23, 2009, the last reported sales price of our common stock on the NYSE was $17.68 per share. As of that date, there were approximately 2,530 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 65/8% Senior Subordinated Notes due 2014 and 2016 and our 71/8% Senior Subordinated Notes due 2018 could restrict our ability to pay cash dividends.

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, 2008.

	Maximum Number (or Approximate

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	Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs
October 1 October 31, 2008	867	$ 30.28		
November 1 November 30, 2008	4,804	20.76		
December 1 December 31, 2008	1,159	20.37		
Total	6,830	$ 21.90		

(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.

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Stockholder Return Performance Presentation

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

$100 was invested in our common stock, the S&P 500 Index and our peer group on December 31, 2003 at the closing price on such date;

investment in our peer group was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of the period; and

dividends were reinvested on the relevant payment dates.

Our peer group consists 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.

Total Return Analysis	**12/31/2003**	**12/31/2004**	**12/31/2005**	**12/31/2006**	**12/31/2007**	**12/31/2008**
Newfield Exploration Company	$ 100.00	$ 132.57	$ 224.80	$ 206.27	$ 236.61	$ 88.67
Peer Group	$ 100.00	$ 132.30	$ 204.27	$ 196.72	$ 293.74	$ 177.99
S&P 500	$ 100.00	$ 110.85	$ 116.29	$ 134.50	$ 141.80	$ 89.35

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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 Item 2, *Properties* Proved Reserves and Future Net Cash Flows and Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations,* of this report.

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(In millions, except per share data)				
Income Statement Data:					
Oil and gas revenues	$ 2,225	$ 1,783	$ 1,673	$ 1,762	$ 1,350
Income (loss) from continuing operations	(373)	172	610	342	331
Net income (loss)	(373)	450	591	348	312
Earnings (loss) per share:					
Basic					
Income (loss) from continuing operations	(2.88)	1.35	4.82	2.73	2.84
Net income (loss)	(2.88)	3.52	4.67	2.78	2.68
Diluted					
Income (loss) from continuing operations	(2.88)	1.32	4.73	2.68	2.79
Net income (loss)	(2.88)	3.44	4.58	2.73	2.63
Weighted average number of shares outstanding for basic earnings per share	129	128	127	125	117
Weighted average number of shares outstanding for diluted earnings per share	129	131	129	128	119
Cash Flow Data:					
Net cash provided by continuing operating activities	$ 854	$ 1,166	$ 1,392	$ 1,119	$ 1,006
Net cash used in continuing investing activities	(2,253)	(865)	(1,552)	(1,015)	(1,584)
Net cash provided by (used in) continuing financing activities	1,173	(117)	174	(124)	613
Balance Sheet Data (at end of period):					
Total assets	$ 7,305	$ 6,986	$ 6,635	$ 5,081	$ 4,327
Long-term debt	2,213	1,050	1,048	870	992
Reserve Data (at end of period):					
Proved reserves:					
Oil and condensate (MMBbls)	140	114	114	102	91
Gas (Bcf)	2,110	1,810	1,586	1,391	1,241
Total proved reserves (Bcfe)	2,950	2,496	2,272	2,001	1,784
Present value of estimated future after-tax net cash flows	$ 2,929	$ 4,531	$ 3,447	$ 5,053	$ 3,602

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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 natural gas and crude oil 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 and, recently, declined materially. 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 continued and 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 resulted in a ceiling test writedown 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 being depleted by production. Please see the 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, 2008. Substantial capital expenditures are required to find, develop and acquire oil and gas 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 are likely to experience significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of December 31, 2008, we had derivative assets of $908 million, of which 60% was measured based upon our valuation model 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* and Note 5, Commodity Derivative Instruments, and Note 8, Fair Value Measurements, to our consolidated financial statements appearing later in this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Results of Operations

Significant Transactions. We completed several significant transactions during 2008 and 2007 that affect the comparability of our results of operations and cash flows from period to period.

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 3, Discontinued Operations, Note 4, Oil and Gas Assets, and Note 5, Commodity Derivative Instruments, to our consolidated financial statements appearing later in this report for a discussion regarding these transactions.

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. Beginning in the fourth quarter of 2005, we elected not to designate any future price risk management activities as accounting hedges under SFAS No. 133. As a result, none of our outstanding hedging contracts as of December 31, 2008 are designated for hedge accounting and the settlement of all hedging contracts during 2008 had no effect on reported revenues. However, revenues for the years ended December 31, 2007 and 2006 include losses on the settlement of hedging contracts designated for hedge accounting of $7 million and $41 million, respectively. Please see Note 5, Commodity Derivative Instruments, to our consolidated financial statements appearing later in 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 $2.2 billion for 2008 were 25% higher than 2007 revenues due to higher oil production and higher average realized prices for oil and gas partially offset by lower gas production. Revenues of $1.8 billion for 2007 were 7% higher than 2006 revenues due to higher oil production and higher average realized oil prices offset by lower gas production and lower average realized gas prices.

	Year Ended December 31,		
	2008	2007	2006
Production[1]:			
Domestic:			
Natural gas (Bcf)	172.9	192.8	198.7
Oil and condensate (MBbls)	6,136	6,501	6,218
Total (Bcfe)	209.8	231.8	236.0
International:			
Natural gas (Bcf)			
Oil and condensate (MBbls)	4,439	2,258	1,097
Total (Bcfe)	26.6	13.5	6.6
Total:			
Natural gas (Bcf)	172.9	192.8	198.7
Oil and condensate (MBbls)	10,575	8,759	7,315
Total (Bcfe)	236.4	245.3	242.6
Average Realized Prices[2]:			
Domestic:			
Natural gas (per Mcf)	$ 7.65	$ 6.33	$ 6.47
Oil and condensate (per Bbl)	86.84	61.32	51.40
Natural gas equivalent (per Mcfe)	8.85	6.98	6.80
International:			
Natural gas (per Mcf)	$	$	$
Oil and condensate (per Bbl)	82.03	69.21	56.58
Natural gas equivalent (per Mcfe)	13.67	11.53	9.43
Total:			
Natural gas (per Mcf)	$ 7.65	$ 6.33	$ 6.47
Oil and condensate (per Bbl)	84.82	63.35	52.18
Natural gas equivalent (per Mcfe)	9.39	7.23	6.87

(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. Had we included the effects of contracts not so designated, our average realized price for total gas would have been $7.12, $7.62 and $7.22 per Mcf for 2008, 2007 and 2006, respectively. Our total oil and condensate average realized price would have been $69.13, $55.04, and $50.25 per Bbl for 2008, 2007 and 2006, respectively. Without the effects of any hedging contracts, our average realized prices for 2008, 2007 and 2006 would have been $7.65, $6.33 and $6.42 per Mcf, respectively, for gas and $84.82, $64.12 and $59.13 per barrel, respectively, 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.

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Domestic Production. Reported total domestic production for the three years ended December 31, 2008 was significantly impacted by the sale of our shallow water Gulf of Mexico assets in August 2007. As a result, our 2008 domestic gas and oil production (stated on a natural gas equivalent basis) decreased 9% from 2007. In addition, 2008 was negatively impacted by the deferral of approximately 5 Bcfe related to the 2008 hurricanes in the Gulf of Mexico. Production from our acquisition of Stone Energy Corporation s Rocky Mountain assets in June 2007 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 gas and oil production increased 20% from 2007 due to increased production in our Mid-Continent and Rocky Mountain divisions as a result of continued successful drilling efforts.

Our 2007 domestic gas and oil production (stated on a natural gas equivalent basis) decreased 2% from 2006. Our 2007 natural gas production decreased 3% from 2006 levels primarily as a result of the sale of our shallow water Gulf of Mexico assets in August 2007 partially offset by an increase in production in the Mid-Continent as a result of successful drilling efforts, and in the Rocky Mountains as a result of our asset acquisition there in June 2007. Our 2006 Gulf of Mexico production was negatively impacted (16 Bcfe) by production deferrals related to the hurricanes in the Gulf of Mexico in 2005. Our 2007 domestic oil and condensate production increased 5% over 2006 primarily due to increased sales from our Monument Butte field.

International Production. Our 2008 international oil production (stated on a natural gas equivalent basis) increased 97% over 2007 primarily due to new field developments on PM 318 and PM 323 in Malaysia. Our 2007 international oil and gas production increased 106% from 2006 primarily due to the commencement of liftings in China in August 2006 and from our Abu field in Malaysia in July 2007 and the timing of liftings of oil production in Malaysia and China.

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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 transactions during 2008 and 2007 and the significant 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, 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 and other impairments	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 an Mcfe basis, increased 169% over 2007 due primarily to a full cost ceiling test writedown and goodwill impairment charge. The components of the period to period change are as follows:

Lease operating expense (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 Hurricanes Katrina and Rita, 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 depreciation, depletion and amortization (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.

General and administrative (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 recent decline in our market capitalization.

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

International Operations. Our international operating expenses for 2008, stated on an 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.

Year ended December 31, 2007 compared to December 31, 2006

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2007.

	Unit-of-Production Year Ended December 31, (Per Mcfe)		Percentage Increase (Decrease)	Total Amount Year Ended December 31, (In millions)		Percentage Increase (Decrease)
	2007	2006		2007	2006	
Domestic:						
Lease operating	$ 1.21	$ 1.11	9%	$ 281	$ 261	7%
Production and other taxes	0.31	0.21	48%	73	49	48%
Depreciation, depletion and amortization	2.78	2.59	7%	643	611	5%
General and administrative	0.65	0.49	33%	150	116	31%
Other		(0.04)	100%		(11)	100%
Total operating expenses	4.95	4.36	14%	1,147	1,026	12%
International:						
Lease operating	$ 2.41	$ 2.22	9%	$ 33	$ 15	123%
Production and other taxes	2.10	1.77	19%	28	12	143%
Depreciation, depletion and amortization	2.85	1.96	45%	39	13	199%
General and administrative	0.35	0.44	(20)%	5	2	64%
Ceiling test writedown		0.94	(100)%		6	(100)%
Total operating expenses	7.71	7.33	5%	105	48	116%
Total:						
Lease operating	$ 1.28	$ 1.14	12%	$ 314	$ 276	14%
Production and other taxes	0.41	0.25	64%	101	61	67%
Depreciation, depletion and amortization	2.78	2.57	8%	682	624	9%
General and administrative	0.63	0.48	31%	155	118	32%
Ceiling test writedown		0.03	(100)%		6	(100)%
Other		(0.04)	100%		(11)	100%
Total operating expenses	5.10	4.43	15%	1,252	1,074	17%

Domestic Operations. Our total domestic operating expenses for 2007, stated on an Mcfe basis, increased 14% over 2006. The period to period change was primarily related to the following items:

LOE in 2007 was adversely impacted by higher operating costs for all of our operations and ongoing repair expenditures of $52 million ($0.22 per Mcfe) related to the 2005 storms. The increase was offset by the sale of all of our producing properties in the shallow water Gulf of Mexico in August 2007, which properties have relatively high LOE per Mcfe. Without the impact of the repair expenditures related to the 2005 storms, our

2007 LOE would have been $0.99 per Mcfe. Our 2006 LOE was negatively impacted by the difference ($0.07 per Mcfe) between insurance proceeds received from the settlement of claims related to the 2005 storms and actual repair expenditures during 2006. Without the impact of the costs related to the repairs for the 2005 storms in excess of our insured amounts, our 2006 LOE would have been $1.04 per Mcfe.

Production and other taxes in 2007 increased $0.10 per Mcfe because of an increase in the proportion of our production subject to taxes as a result of increased production from our Mid-Continent and Rocky Mountain operations and the Gulf of Mexico property sale. In addition, during 2006, we recorded refunds of $18 million ($0.07 per Mcfe) related to production tax exemptions on certain high cost gas wells, compared to refunds of only $8 million ($0.04 per Mcfe) recorded during 2007.

The increase in our DD&A rate resulted from higher cost reserve additions, offset by the proceeds from the Gulf of Mexico property sale and the sale of our coal bed methane assets in the Cherokee Basin. The component of DD&A associated with accretion expense related to our asset retirement obligation was $0.04 per Mcfe for 2007 and $0.06 per Mcfe for 2006. The decrease in accretion expense is due to the significant reduction in our asset retirement obligation resulting from the Gulf of Mexico property sale. Please see Note 1, Organization and Summary of Significant Accounting Policies *Accounting for Asset Retirement Obligations*, to our consolidated financial statements.

G&A expense increased $0.16 per Mcfe in 2007 due to additional bonus expense of $17 million ($0.07 per Mcfe) under our incentive compensation plan associated with the gain from the sale of our interests in the U.K. North Sea, an increase in a litigation settlement reserve associated with a statewide royalty owner class action lawsuit in Oklahoma and continued growth in our workforce. During 2007, we capitalized $49 million ($0.21 per Mcfe) of direct internal costs as compared to $40 million ($0.17 per Mcfe) in 2006. Capitalized direct internal costs in 2007 include $5 million ($0.02 per Mcfe) related to additional bonus expense associated with the U.K. North Sea sale.

Other expenses for 2006 include the following items:

In 2006, we redeemed all $250 million principal amount of our 83/8% Senior Subordinated Notes due 2012. We recorded a charge for the $19 million early redemption premium we paid and a charge of $8 million for the remaining unamortized original issuance costs for the notes.

In 2006, we recorded a $37 million benefit from our business interruption insurance coverage relating to the disruptions to our operations caused by the 2005 hurricanes.

International Operations. Our international operating expenses for 2007, stated on an Mcfe basis, increased 5% compared to 2006. The period to period change was primarily related to the following items:

Total LOE increased significantly due to increased liftings in Malaysia and China during 2007. LOE, on an Mcfe basis, increased 9% due to higher operating costs for our international operations.

Production and other taxes increased $0.33 per Mcfe primarily due to an increase in the tax rate per unit for our oil in Malaysia as a result of substantially higher oil prices.

The DD&A rate increased as a result of higher costs for drilling goods and services in Malaysia.

G&A expense decreased $0.09 per Mcfe primarily due to increased liftings of production in Malaysia and China.

In 2006, we recorded a ceiling test writedown of $6 million associated with ceasing our exploration efforts in Brazil.

Interest Expense. The following table presents information about interest expense for each of the years in the three-year period ended December 31, 2008.

	Year Ended December 31,		
	2008	**2007**	**2006**

	(In millions)		
Gross interest expense:			
Credit arrangements	$ 10	$ 14	$ 3
Senior notes	13	23	24
Senior subordinated notes	87	59	57
Other	2	6	3
Total gross interest expense	112	102	87
Capitalized interest	(60)	(47)	(44)
Net interest expense	$ 52	$ 55	$ 43

The increase in gross interest expense in 2008 resulted primarily from the May 2008 issuance of $600 million principal amount of our 71/8% Senior Subordinated Notes due 2018.

The increase in gross interest expense in 2007 resulted primarily from higher debt levels outstanding under our credit arrangements as compared to 2006. Prior to the sale of our shallow water Gulf of Mexico assets, we financed our capital shortfall and our acquisition of Stone Energy s Rocky Mountain assets with cash on hand and borrowings under our credit arrangements. Following the sale, we repaid all of our outstanding borrowings under our credit arrangements and $125 million principal amount of our 7.45% Senior Notes that became due in October 2007.

We capitalize interest with respect to our unproved properties. 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). Commodity derivative income during 2008 increased $596 million over the expense recognized in 2007. However, the change in commodity derivative income (expense) between 2007 and 2006 was an increase in commodity derivative expense of $577 million. The significant fluctuation in these amounts from year to year is due to the extreme volatility of crude oil and natural gas prices during these periods.

Taxes. The effective tax rates for the years ended December 31, 2008, 2007 and 2006 were 30%, 41% and 36%, 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 2008 decreased because 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 did not generate a tax benefit. Our effective tax rate for 2007 increased from 2006 levels due to $26 million of interest income on intercompany loans to our international subsidiaries that was included in the determination of U.S. federal income taxes. However, the related intercompany interest expense was recognized by several of our international subsidiaries that are located in non-taxing international jurisdictions.

Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing, amount, and location of future production 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. In light of the current economic outlook and commodity price environment, we intend to limit our 2009 capital expenditures to $1.45 billion, which is a level that we expect can be funded with cash flow from operations, thereby preserving liquidity under our credit arrangements. Our 2009 capital budget focuses on those projects that we believe will generate and lay the foundation for production growth. We have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations.

Although we have reduced our 2009 capital budget to a level that we believe corresponds with our anticipated 2009 cash flows, the timing of capital expenditures and the receipt of cash flows do not necessarily match, and we anticipate borrowing and repaying funds under our credit arrangements throughout the year. For example, our planned capital expenditures are front-end loaded and we expect to outspend cash flows in the first half of the year. We may have to further reduce capital expenditures and our ability to execute our business plans could be diminished 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

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requirements or for other reasons or (3) our customers or working interest owners default on their obligations to us.

We continue to hold auction rate securities with a fair value of $59 million. We will attempt to sell these securities every 7-28 days until the auction succeeds, the issuer calls the securities or the securities mature. We currently do not believe that the decrease in the fair value of these investments is permanent or that the failure of the auction mechanism will have a material impact on our liquidity given the amount of our available borrowing capacity under our credit arrangements. See Note 8, Fair Value Measurements 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 as agent. As of December 31, 2008, 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 amount that we may borrow under the facility is determined by our lenders annually each May (and may be redetermined 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. 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 $135 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 later in this report.

At February 23, 2009, we had outstanding borrowings of $629 million under our $1.25 billion credit facility and $26 million outstanding under our money market lines of credit and we had approximately $703 million of available borrowing capacity under our credit arrangements.

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 because our capital spending generally has exceeded our cash flows from operations and we generally use excess cash to pay down borrowings under our credit arrangements. For the full year 2009, we expect that our capital spending plans will match our total cash flows from 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.

At December 31, 2007, we had a working capital deficit of $2 million compared to a working capital deficit of $272 million at the end of 2006. Our current assets at December 31, 2007, include $370 million of cash and short-term investments remaining from the proceeds of our 2007 property sales compared to $90 million at the end of 2006. Our working capital position at December 31, 2007 was positively affected by a reduction in our asset retirement obligation of $30 million due to the sale of our shallow water Gulf of Mexico assets. At December 31, 2007, our working capital deficit included a net derivative liability of $84 million compared to a net derivative asset of $200 million at December 31, 2006.

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

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contracts and changes in working capital. We sell substantially all of our natural gas and oil production under floating market contracts. However, we generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 12-24 months. See Oil and Gas Hedging below.

We typically receive the cash associated with accrued 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 is impacted by changes in working capital and is not affected by DD&A, ceiling test writedowns and other impairments, or other non-cash charges or credits.

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 payment of $558 million 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, and 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 $1.2 billion in 2007, a decrease of 17% compared to cash flow from operations of $1.4 billion in 2006. Although our 2007 production volumes were impacted by our property sales, higher commodity prices offset the cash flow impact of these property sales during the year. Realized oil and gas prices (on a natural gas equivalent basis), including the effects of hedging contracts (regardless of whether designated for hedge accounting), increased 7% over 2006. Our working capital requirements during 2007 increased compared to 2006 as a result of increased drilling activities, the timing of payments made by us to vendors and other operators, and the timing and amount of advances received from our joint operators.

Cash Flows from Investing Activities. Net cash used in investing activities (both continuing and discontinued) for 2008 was $2.3 billion compared to $906 million for 2007.

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.

During 2007, we:

- spent $2.6 billion (including $658 million for acquisitions of oil and gas properties);
- received proceeds of $1.3 billion from sales of U.S. oil and gas properties ($1.1 billion from our shallow water Gulf of Mexico assets, $128 million from our coal bed methane assets in the Cherokee Basin of Oklahoma and $125 million from various other oil and gas properties);
- received proceeds of $491 million (net of cash on hand at the date of sale) for the sale of our interests in the U.K. North Sea; and
- purchased investments of $271 million and redeemed investments of $172 million.

Capital Expenditures. 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 and domestic leasehold activity (includes the acquisition of properties in South Texas) and $225 million internationally.

Our capital spending of $2.6 billion for 2007 increased 51% from our $1.7 billion of capital spending during 2006. These amounts exclude recorded asset retirement obligations of $21 million in 2007 and $11 million in 2006. Of the $2.6 billion spent in 2007, we invested $1.4 billion in domestic exploitation and development, $240 million in domestic exploration (exclusive of exploitation and leasehold activity),

$736 million in acquisitions and domestic leasehold activity (including $578 million for the Rocky Mountain asset acquisition) and $236 million internationally.

We have budgeted $1.45 billion for capital spending in 2009, including $130 million of estimated capitalized interest and overhead. Approximately 43% of the $1.45 billion is allocated to the Mid-Continent, 17% to the Rocky Mountains, 18% to the Gulf of Mexico, 14% to onshore Texas, and 8% to international projects. See Item 1, *Business* Our Properties and Plans for 2009. The 2009 budget is based on our commitment to live within expected cash flow from operations. 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. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable.

Cash Flows from Financing Activities. Net cash flow provided by financing activities (both continuing and discontinued) for 2008 was $1.2 billion compared to $79 million of net cash flow used in financing activities for 2007.

During 2008, we:

- borrowed $2.6 billion and repaid $2.0 billion under our credit arrangements;
- issued $600 million aggregate principal amount of our 71/8% 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.

During 2007, we:

- borrowed and repaid $2.9 billion under our credit arrangements;
- repaid $125 million principal amount of our 7.45% Senior Notes at their maturity in October 2007;
- received proceeds of $32 million from the issuance of shares of our common stock upon the exercise of stock options; and
- received a $14 million tax benefit from the exercise of stock options.

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Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of December 31, 2008.

	Total	Less than 1 Year	2-3 Years (In millions)	4-5 Years	More than 5 Years
Debt:					
Revolving credit facility	$ 514	$	$	$ 514	$
Money market lines of credit	47			47	
75/8% Senior Notes due 2011	175		175		
65/8% Senior Subordinated Notes due 2014	325				325
65/8% Senior Subordinated Notes due 2016	550				550
71/8% Senior Subordinated Notes due 2018	600				600
Total debt	2,211		175	561	1,475
Other obligations:					
Interest payments(1)	868	122	237	205	304
Net derivative liabilities (assets)	(908)	(662)	(244)	(2)	
Asset retirement obligations	81	11	4	9	57
Operating leases	190	96	44	17	33
Deferred acquisition payments	11	11			
Oil and gas activities(2)	757				
Total other obligations	999	(422)	41	229	394
Total contractual obligations	$ 3,210	$ (422)	$ 216	$ 790	$ 1,869

(1) Interest associated with our revolving credit facility and money market lines of credit was calculated using a weighted average interest rate of 1.387% at December 31, 2008 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, 2008, these work-related commitments totaled $757 million and were comprised of $613 million domestically and $144 million internationally. A significant portion of the domestic amount is related to 10-year firm transportation agreements for our Mid-Continent production. These obligations are subject to the completion of construction and required regulatory approvals. Actual amounts are not included by maturity because their timing cannot be accurately predicted.

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 75/8% 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.

We have an interest rate swap agreement that provides for us to pay variable and receive fixed interest payments and is designated as a fair value hedge of a portion of our senior notes (see Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* and Note 9, Debt *Interest Rate Swap*, to our consolidated financial statements).

Senior Subordinated Notes. In August 2004, we issued $325 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2014. In April 2006, we issued $550 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2016. In May 2008, we issued $600 million aggregate principal amount of our 71/8% Senior Subordinated Notes due 2018. 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 65/8% notes due 2014 at any time on or after September 1, 2009 and some or all of our 65/8% 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 65/8% notes due 2014 prior to September 1, 2009 and all but not part of our 65/8% notes due 2016 prior to April 15, 2011, in each case, at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. In addition, before April 15, 2009, we may redeem up to 35% of the original principal amount of our 65/8% notes due 2016 with net cash proceeds from certain sales of our common stock at 106.625% of the principal amount plus accrued and unpaid interest to the date of redemption.

We may redeem some or all of our 71/8% 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 71/8% 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 71/8% 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.

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.

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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 natural gas production for the next 12-24 months to reduce our exposure to fluctuations in natural gas and oil 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 23, 2009, approximately 69% of our estimated 2009 production was subject to derivative contracts (including basis contracts). In 2008, 72% of our production was subject to derivative contracts, compared to 87% in 2007 and 57% in 2006.

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. At December 31, 2008, Barclays Capital, JPMorgan Chase Bank, N.A., Merrill Lynch Commodities, Inc., J Aron & Company, Bank of Montreal and Bank of America, N.A. were the counterparties with respect to 87% of our future hedged production. Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX. Historically, a majority of our hedged natural gas and crude oil production has been sold at market prices that have had a high positive correlation to the settlement price for such hedges. With the sale of our Gulf of Mexico shelf production and the corresponding shift in the geographic distribution of our natural gas production, we have begun to utilize basis hedges to a greater extent.

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 $0.40-$0.60 per MMBtu less than the Henry Hub Index. Realized gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average 70-80% of the Henry Hub Index. Beginning in the second quarter of 2009, our realized prices for our Mid-Continent properties should improve to 80-85% of the Henry Hub Index as we begin to utilize our agreements that provide guaranteed pipeline capacity at a fixed price to move this natural gas production to the Perryville markets. In light of potential basis risk with respect to our Rocky Mountain proved producing fields acquired from Stone Energy, we have hedged the basis differential for about 40% of our estimated production for 2009 through 2012 to lock in the differential at a weighted average of $0.98 per MMBtu less than the Henry Hub Index. 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 96-98% of the WTI price. Oil sales from our operations in Malaysia typically sell at a slight discount to Tapis, or about 90% of WTI. Oil sales from our operations in China typically sell at $10-$15 per barrel less than the WTI price.

Between January 1, 2009 and February 23, 2009, we entered into additional natural gas derivative contracts set forth in the table below. None of these contracts have been designated for hedge accounting.

Period and Type of Contract	Volume in MMMBtus	Weighted Average NYMEX Contract Price per MMBtu
January 2009-March 2009		
Price swap contracts	310	$ 6.35
April 2009-June 2009		
Price swap contracts	910	6.35
July 2009-September 2009		
Price swap contracts	920	6.35
October 2009-December 2009		
Price swap contracts	6,495	6.36
January 2010-March 2010		
Price swap contracts	24,600	6.34
April 2010-June 2010		
Price swap contracts	24,840	6.26
July 2010-September 2010		
Price swap contracts	25,080	6.26
October 2010-December 2010		
Price swap contracts	21,250	6.41

Please see the discussion and tables in Note 5, Commodity Derivative Instruments, to our consolidated financial statements appearing later in this report for a description of the accounting applicable to our hedging program, a listing of open contracts as of December 31, 2008 and the estimated fair market value of those contracts as of that date.

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 period-end prices and costs and a 10% discount rate.

Full Cost Method. We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized into cost centers (the amortization base) that are established on a country-by-country basis. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that are estimated to directly relate to our 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 natural gas and crude oil reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs 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 increase our domestic DD&A rate by $0.01 per Mcfe for 2008 would have required a decrease in our estimated proved reserves at December 31, 2007 of approximately 15 Bcfe. Due to the relatively small size of our international full cost pools for Malaysia and China, any decrease in reserves associated with the respective country s full cost pool would significantly increase the DD&A rate in that country. However, since production from our international operations represented only about 11% of our consolidated production for 2008, a change in our international DD&A expense 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 calculation dictates that prices and costs in effect as of the last day of the quarter are held constant. However, we may not be subject to a writedown if prices increase subsequent to the end of a quarter in which a writedown might otherwise be required. The full cost ceiling test impairment calculations also take into consideration the effects of hedging contracts that are designated for hedge accounting, however, since October 2005, we elected not to designate any future price risk management activities as accounting hedges.

At December 31, 2008, the ceiling value of our domestic oil and gas reserves was calculated based upon quoted market prices of $5.71 per MMBtu for gas and $44.61 per barrel for oil, adjusted for market differentials. Using these prices, the net capitalized costs of our domestic oil and gas properties exceeded the ceiling by approximately $1.1 billion (net-of-tax) at December 31, 2008 and resulted in a writedown. Calculating the ceiling value of our domestic oil and gas reserves utilizing current commodity prices, holding all other factors constant, would result in another significant writedown of our domestic oil and gas properties in the first quarter of 2009. At December 31, 2008, the net capitalized costs of our oil and gas properties in Malaysia exceeded the ceiling by approximately $68 million (net-of-tax) and resulted in a writedown. Any decrease in oil prices below those at December 31, 2008 may result in additional ceiling test writedowns in Malaysia in the first quarter of 2009. At December 31, 2008, the ceiling with respect to our oil and gas properties in China exceeded the net capitalized costs of the properties by approximately $9 million, requiring no writedown. It is possible that we could experience a ceiling test writedown in China in 2009 if oil prices were to decline to approximately $38 per Bbl, holding all other factors constant. Given the fluctuation of natural gas and oil prices, it is reasonably possible that the estimated discounted future net cash flows from our proved reserves will change in the near term. If natural gas and oil prices continue to 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, 2008, we had a total of approximately $1.3 billion of costs excluded from the amortization base of our respective full cost pools. Because the application of the full cost ceiling test at December 31, 2008 resulted in an excess of the carrying value of our oil and gas properties over their respective cost-center ceilings, inclusion of some or all of our unevaluated property costs in the respective amortization base, without adding any associated reserves, would have resulted in larger ceiling test writedowns.

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 for future abandonment costs is set forth by SFAS No. 143. This standard 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 increase our domestic DD&A rate by $0.01 per Mcfe for the year ended December 31, 2008 would have required an increase in the estimate of our future development and abandonment costs at December 31, 2007 of approximately $39 million. Due to the relatively small size of our international full cost pools in Malaysia and China, a change greater than $56 million and $10 million, respectively, in future development or abandonment costs associated with the respective country s full cost pool would increase the DD&A rate in that country by 10%. However, since production from our international operations represented only about 11% of our consolidated production for 2008, a change in our international DD&A expense would not have materially affected our consolidated results of operations. In addition, because the application of the full cost ceiling test at December 31, 2008 resulted in an excess of the carrying value of our U.S. and Malaysian oil and gas properties over their respective cost-center ceilings, upward revisions in our estimate of future development and abandonment costs, without adding any associated reserves, would have resulted in larger ceiling test writedowns.

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. Please see New Accounting Standards below for a detailed discussion.

Commodity Derivative Activities. We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future natural gas and oil production. We generally hedge a substantial, but varying, portion of our anticipated oil and natural 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 natural gas production. Beginning on October 1, 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 required under SFAS No. 157. These factors include not only the impact of our nonperformance 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. On January 1, 2006, we adopted Financial Accounting Standards Board (FASB) Statement (SFAS) No. 123 (revised 2004) (SFAS No. 123(R)), *Share-Based Payment,* to account for stock-based compensation. Among other items, SFAS No. 123(R) eliminated the use of Accounting Principles Board Opinion No. 25 (APB 25), *Accounting for Stock Issued to Employees,* and the intrinsic value method of accounting and requires companies to recognize in their financial statements the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, has been or will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant or modification, has been or will be 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 shares. Prior to the adoption of SFAS No. 123(R), we followed the intrinsic value method in accordance with APB 25 to account for stock-based compensation. See Note 11, Stock-Based Compensation, for a full discussion of our stock-based compensation.

New Accounting Standards

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157). SFAS No. 157 defines fair value, establishes criteria to be considered when measuring fair value and expands disclosures about fair value measurements. In February 2008, the FASB issued staff position No. 157-2, *Effective Date of FASB Statement No. 157* (FSP 157-2), which granted a one-year deferral of the effective date of SFAS No. 157 as it applies to nonfinancial 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). SFAS No. 157 is effective for all recurring measures of financial assets and financial liabilities (e.g. derivatives and investment securities) for fiscal years beginning after November 15, 2007. We adopted the provisions of SFAS No. 157 for all recurring measures of financial assets and liabilities on January 1, 2008. The adoption of SFAS No. 157 did not have a material impact on our financial position or results of operations. We have completed our initial evaluation of the impact of FSP 157-2 and determined that its adoption is not expected to have a material impact on our financial position or results of operations.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations* (SFAS No. 141(R)). SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations.* SFAS No. 141(R) establishes principles and requirements for how the acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The statement 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. SFAS No. 141(R) 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 SFAS No. 141(R) effective January 1, 2009. The adoption of this statement did not impact our consolidated financial statements, but may have a material impact on our financial statements for businesses we acquire post-adoption.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (SFAS No. 161). This statement requires enhanced disclosures about our derivative and hedging activities and is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted SFAS No. 161 effective January 1, 2009. The adoption of this statement will increase the disclosures in our 2009 consolidated financial statements related to our derivative instruments.

On December 31, 2008, the Securities and Exchange Commission (SEC) issued the final rule, *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. 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. Revised requirements in the Final Rule include, but are not limited to:

Oil and gas reserves must be reported using the unweighted arithmetic average of the first day of the month price for each month within the 12 month period, rather than year-end prices;

Companies will be allowed to report, on an optional basis, probable and possible reserves;

Non-traditional reserves, such as oil and gas extracted from coal and shales, will be included in the definition of oil and gas producing activities;

Companies will be permitted to use new technologies to determine proved reserves, as long as those technologies have been demonstrated empirically to lead to reliable conclusions with respect to reserve volumes;

Companies will be required to disclose, in narrative form, additional details about their proved undeveloped reserves (PUDs), including the total quantity of PUDs at year end, any material changes to PUDs that occurred during the year, investments and progress made to convert PUDs to developed oil

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and gas reserves and an explanation of the reasons why material concentrations of PUDs in individual fields or countries have remained undeveloped for five years or more after disclosure as PUDs; and

Companies will be required to report the qualifications and measures taken to assure the independence and objectivity of any business entity or employee primarily responsible for preparing or auditing the reserves estimates.

We are currently evaluating the impact of adopting the Final Rule. The SEC is discussing the Final Rule with the FASB staff to align FASB accounting standards with the new SEC rules. These discussions may delay the required compliance date. Absent any change in the effective date, we will comply with the disclosure requirements in our annual report on Form 10-K for the year ended December 31, 2009.

Regulation

Exploration and development and the production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. An overview of this regulation 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 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 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; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue. In the past, the federal government regulated the prices at which 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. 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. Our oil and gas leases in the Gulf of Mexico and many of our leases in the Rocky Mountains 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.

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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. Please see the table under Acreage Data in Item 2 of this report. 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 existence and are currently amending these plans or, as necessary, developing new SPCC plans that will satisfy new SPCC plan certification and implementation requirements that become effective in July 2009.

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 U.S. Environmental Protection Agency, also known as 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) 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.

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.

BOPD. Barrels of oil per day.

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

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

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

Developed 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 natural gas field 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 2006, 2007 and 2008 and expect to drill in 2009 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. A well drilled to find and produce oil or natural gas reserves that is not a development 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 natural 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. Reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery.

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 proved developed reserves in Rule 4-10(a)(3) of Regulation S-X.

Proved reserves. In general, the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(2) of Regulation S-X.

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 proved undeveloped reserves in Rule 4-10(a)(4) 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 natural 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 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 natural gas and oil 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, Commodity Derivative Instruments, to our consolidated financial statements appearing later in this report.

Interest Rates

At December 31, 2008, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Bank revolving credit facility	$	$ 514
Money market lines of credit		47
75/8% Senior Notes due 2011[(1)]	125	50
65/8% Senior Subordinated Notes due 2014	325	
65/8% Senior Subordinated Notes due 2016	550	
71/8% Senior Subordinated Notes due 2018	600	
Total debt	$ 1,600	$ 611

(1) $50 million principal amount of our 75/8% 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.

We consider our interest rate exposure to be minimal because only about 28% of our debt was at variable rates, after taking into account our interest rate swap agreement. Our variable rate debt is currently at an interest rate of less than

2%.

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, 2008.

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, 2008.

The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

David A. Trice Chief Executive Officer	Terry W. Rathert Senior Vice President and Chief Financial Officer

Houston, Texas
February 27, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of Newfield Exploration Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of stockholder s equity and of cash flows present fairly, in all material respects, the financial position of Newfield Exploration Company and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

Houston, Texas
February 27, 2009

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NEWFIELD EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEET
(In millions, except share data)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 24	$ 250
Short-term investments		120
Accounts receivable	375	332
Inventories	96	82
Derivative assets	663	72
Deferred taxes		35
Other current assets	48	36
Total current assets	1,206	927
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,303 and $1,189 were excluded from amortization at December 31, 2008 and 2007, respectively)	10,349	9,857
Less accumulated depreciation, depletion and amortization	(4,591)	(3,899)
	5,758	5,958
Derivative assets	247	17
Long-term investments	72	
Other assets	22	22
Goodwill		62
Total assets	$ 7,305	$ 6,986
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 103	$ 52
Accrued liabilities	672	671
Advances from joint owners	73	44
Asset retirement obligation	11	6
Derivative liabilities		156
Deferred taxes	226	
Total current liabilities	1,085	929
Other liabilities	22	18

Derivative liabilities		248
Long-term debt	2,213	1,050
Asset retirement obligation	70	56
Deferred taxes	658	1,104
Total long-term liabilities	2,963	2,476
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, 2008 and 2007; 133,985,751 and 133,232,197 shares issued at December 31, 2008 and 2007, respectively)	1	1
Additional paid-in capital	1,335	1,278
Treasury stock (at cost, 1,908,243 and 1,896,286 shares at December 31, 2008 and 2007, respectively)	(32)	(32)
Accumulated other comprehensive income (loss):		
Unrealized loss on investments	(13)	
Unrealized gain (loss) on pension assets	2	(3)
Retained earnings	1,964	2,337
Total stockholders equity	3,257	3,581
Total liabilities and stockholders equity	$ 7,305	$ 6,986

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, 2008	2007	2006
Oil and gas revenues	$ 2,225	$ 1,783	$ 1,673
Operating expenses:			
Lease operating	265	314	276
Production and other taxes	157	101	61
Depreciation, depletion and amortization	697	682	624
General and administrative	141	155	118
Ceiling test and other impairments	1,863		6
Other	4		(11)
Total operating expenses	3,127	1,252	1,074
Income (loss) from operations	(902)	531	599
Other income (expense):			
Interest expense	(112)	(102)	(87)
Capitalized interest	60	47	44
Commodity derivative income (expense)	408	(188)	389
Other	11	6	11
	367	(237)	357
Income (loss) from continuing operations before income taxes	(535)	294	956
Income tax provision (benefit):			
Current	36	92	30
Deferred	(198)	30	316
	(162)	122	346
Income (loss) from continuing operations	(373)	172	610
Income (loss) from discontinued operations, net of tax		278	(19)
Net income (loss)	$ (373)	$ 450	$ 591
Earnings per share:			
Basic			
Income (loss) from continuing operations	$ (2.88)	$ 1.35	