NEWFIELD EXPLORATION CO /DE/
Form 10-K
February 29, 2008

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, 2007

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 2020, 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
Rights to Purchase Series A Junior Participating Preferred 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. o

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	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 $6 billion as of June 30, 2007 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 25, 2008, there were 131,496,126 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 1, 2008, which is incorporated by reference into Part III of this Form 10-K.

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PART III

PART IV

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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 an 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.

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. Internationally, we are 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 or furnish them. 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

Our company was founded in 1989. For the first 10 years of our existence, we focused on the shallow waters of the Gulf of Mexico. In the late-1990s, we began to expand our operations into other regions to gain access to properties and opportunities necessary for our continued growth. Cash flows from our Gulf of Mexico operations funded this expansion. 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, 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 2007, we had proved reserves of 2.5 Tcfe. Those reserves were 73% natural gas and 63% proved developed. As a result of our focus on unconventional resource plays in the Rocky Mountains and Mid-Continent and the sale of our shallow water Gulf of Mexico assets in August 2007, our reserve life index is now more than 10 years. Of our year-end 2007 reserves:

- 45% were located in the Mid-Continent;
- 28% were located in the Rocky Mountains;
- 19% were located onshore Texas;
- 4% were located in the Gulf of Mexico; and
- 4% were located internationally.

By geographical region, we expect the sources of our 2008 budgeted production will be:

33% from the Mid-Continent;

19% from the Rocky Mountains;

30% from onshore Texas;

6% from the Gulf of Mexico; and

12% from international operations.

Increased Focus on Resource Plays

In part, the changes in our asset base are reflective of broader trends underway in our industry. 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 rely on technological advances, hands on experience, repeatability and strong commodity prices. Today, we have two large resource plays the Woodford Shale and Monument Butte and are active in several other plays.

Mid-Continent. Our largest single investment area over the last two years has been the Woodford Shale play, located in the Arkoma Basin of southeast Oklahoma. Our activities began in this area in 2003, and our early success in drilling led to the leasing of approximately 165,000 net acres. Since 2003, we have drilled more than 100 vertical wells and 160 horizontal wells to delineate our acreage position. The Woodford formation is a shale interval that varies in thickness from 100 200 feet throughout our acreage. At year-end 2007, our production was 165 MMcfe/d gross. The field has thousands of drilling locations. Our efforts are focused primarily on determining the appropriate spacing for our development wells. In 2008, we will drill pilots on both 40- and 80-acre spacing.

In addition to the Woodford Shale, our activities in the Mid-Continent are focused on the Mountain Front Wash play in the Anadarko Basin. Our production there reached a record level of 97 MMcfe/d in early 2008. Our largest producing field in the play is Stiles Ranch, where our working interest is predominately 100%.

Monument Butte. In August 2004, we purchased the giant Monument Butte oil field, located in the Uinta Basin of northeastern Utah. Since our acquisition, we have drilled nearly 700 wells. At year-end 2007, the field had more than 1,100 producing oil wells and gross daily production was nearly 14,000 BOPD. The field has thousands of remaining infill drilling opportunities. As in past years, we plan to drill approximately 200 wells in the field in 2008. Our activity levels in the field are dictated, in large part, by refining demand in the region and our ability to obtain drilling permits in a timely manner. Recent increased demand for Monument Butte crude oil is encouraging, and we expect to have sufficient drilling permits to allow us to run a four or five rig drilling program throughout 2008.

Green River Basin. More than half of the proved reserves associated with the 2007 Rockies acquisition are located in the Pinedale field in Sublette County, Wyoming. We acquired interests in 8,000 gross acres (4,000 net acres) in the southeastern portion of the anticline. We see the potential to drill 100 additional locations as field spacing is decreased to 20 acres and eventually 10 acres. In 2007, we reached an agreement to assume operatorship of our activities in Pinedale. Approximately 13% of the reserves in our 2007 Rocky Mountain acquisition were located in the Jonah field, where we have identified more than 40 development locations on 10- and 5-acre well spacing.

Williston Basin. Approximately 20% of the reserves associated with our 2007 Rockies acquisition were located in the Williston Basin. We have an interest in approximately 150,000 net acres. Current net production is more than 3,200 BOPD and has benefited from a recent well re-fracture program and new drilling in the Elm Coulee field, a mature Bakken play. Other targeted formations include the Madison, Red River and Duperow.

Continued Focus on Conventional Plays

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

Onshore Texas. We are active in several plays in South Texas, in the Val Verde Basin of West Texas and in plays in East Texas. In South Texas, we have been very active under a joint venture agreement with ExxonMobil that is focused on the Frio play. This joint venture allows us to access new properties and to apply our knowledge in this area. Over the last three years, we have drilled 23 successful wells and grown production from zero to 75 MMcfe/d gross as of year-end 2007. Our wells in South Texas have high initial production rates and steep declines, so continued drilling is required to grow production. In the Val Verde Basin, our efforts are focused on the Canyon, Strawn and Ellenberger formations. Since entering the basin in

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2002, we have grown production from approximately 20 MMcfe/d to approximately 70 MMcfe/d in early 2008. We have an interest in 130,000 gross acres. We believe that we have an opportunity for future growth in this area but growth will largely depend on our ability to have exploration success.

Gulf of Mexico. Today, our efforts in the Gulf of Mexico are primarily focused on the deepwater. Our deepwater programs provide us with significant reserve exposure and represent a substantial component of our ongoing exploration efforts. We have two field developments underway and plans to drill four or five deepwater exploratory wells per year for the next several years from an inventory of leads and prospects we acquired in recent lease sales. Although we sold our shallow water Gulf of Mexico assets in 2007, we continue to make selective investments there to take advantage of the regional expertise of our employees and our significant 3-D seismic data base.

International. We are active offshore Malaysia and China. We expect that more than 75% of our 2008 international budget will be spent in Malaysia, where we have several oil fields under development. Our activities in Malaysia began in 2004, and we continue to seek new opportunities. In China, we are producing 1,200 BOPD net from Bohai Bay. We also have three offshore exploration concessions we began drilling on two of these concessions in late 2007.

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. To manage the risks associated with our strategy to grow reserves through the drill bit, a substantial majority of the wells we plan to drill in 2008 are lower risk with low to moderate reserve potential. We have lower-risk drilling opportunities in the Mid-Continent, the Rockies and the shallow waters of Malaysia. These opportunities are complemented with higher risk higher reserve potential plays in areas like the deepwater Gulf of Mexico and Malaysia, as well as deeper exploration plays in South Texas.

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 actively pursue the acquisition of proved oil and gas properties in select geographic areas. The potential to add reserves through the drill bit is a critical consideration in our acquisition screening process.

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

Control of Operations and Costs. In general, we prefer to operate our properties. By controlling operations, we can better manage production performance, control operating expenses and capital expenditures, consider the application of technologies and influence timing. At year-end 2007, we operated about 75% of our net total production.

Equity Ownership and Incentive Compensation. We want our employees to act like owners, so we reward and encourage them through equity ownership and performance-based compensation. A significant portion of our employees compensation is contingent on our profitability. As of February 25, 2008, our employees owned or had options to acquire 7% of our outstanding common stock on a diluted basis.

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Our Properties and Plans for 2008

Our capital budget for 2008 is approximately $1.6 billion, excluding $113 million of capitalized interest and overhead. We do not budget for potential acquisitions. Approximately 40% of the budget is allocated to the Mid-Continent, 20% to the Rocky Mountains, 15% to onshore Texas, 15% to the Gulf of Mexico and 10% 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, 2007, we owned an interest in more than 750,000 gross acres and about 2,600 gross producing wells. This region is characterized by longer-lived natural gas production. Although our wells in this region are all fracture stimulated and have high initial production declines, our activity levels are leading to production growth. For 2008, we plan to invest about $620 million in the Mid-Continent. In total, we expect to drill or participate in approximately 200 wells in this focus area in 2008. We have two major activity areas in the region the Woodford Shale in the Arkoma Basin and the Mountain Front Wash play in the Anadarko Basin.

The Woodford Shale play is our most active focus area we plan to invest about $460 million in the play in 2008. We expect to operate 10 12 drilling rigs throughout the year, allowing us to drill about 100 operated horizontal wells. More than half of the wells will have lateral completions in excess of 3,000 feet. Longer laterals help improve our per unit finding and development costs. Nearly half of the planned wells will be drilled from common surface locations or pads, decreasing the footprint of our operations on the environment and providing further cost efficiencies. Our average working interest in the play is approximately 58%. In addition, we also will participate in the drilling of 50 60 wells operated by others.

We are planning to operate a 3 5 rig drilling program throughout 2008 in our Mountain Front Wash play. We expect to drill 60 70 wells and invest up to $120 million in the play.

Rocky Mountains. As of December 31, 2007, we owned an interest in about 1.2 million gross acres, approximately 1,800 gross producing wells and 445 water injection 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.

Our largest asset in the Rocky Mountains is the Monument Butte oil field. The field accounts for nearly 20% of year-end 2007 total proved reserves and encompasses more than 100,000 acres. Our working interest in the field averages 86%, and we operate the field and control the timing and pace of our operations. We have thousands of remaining infill drilling locations. Our production growth is influenced by the 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. Substantially all of our Monument Butte production at year-end 2007 was being sold under firm contracts. Production from Monument Butte has benefited from increased demand for its black wax crude oil. We are working to secure additional long-term agreements with refiners. Please see the discussion under *Production growth at Monument Butte may be limited by the demand for our crude oil production* in Item 1A of this report.

We plan to drill 200 wells at Monument Butte in 2008. Our plans include the ongoing development of the field on 40-acre spacing, the conversion of existing producing wells to waterflood injector wells and an increasing number of 20-acre spaced infill wells. Over the last two years, we have drilled more than 50 wells on 20-acre spacing. Results indicate the potential to develop a large portion of the field on 20-acre spacing. A drilling rig is dedicated to this program in 2008.

In 2006, we signed an alliance with the Northern Ute Tribe, allowing us to drill wells on 47,000 gross acres located north and adjacent to Monument Butte. As of mid-February 2008, we had drilled 16 successful wells on this acreage and production has been consistent with wells in the main portion of the field. We will have a rig dedicated to drilling wells on this acreage throughout most of 2008.

There also is the potential for significant gas resources beneath the shallow producing oil sands at Monument Butte. Recent industry wells, as well as a few wells on our acreage that we have participated in, provide encouragement that the Wasatch, Mesa Verde, Blackhawk and Mancos Shale formations can be exploited economically. We have signed an agreement with a third party that allows for promoted exploratory drilling and progressive earning in approximately 71,000 net acres in which we will retain a majority interest. Drilling under this agreement is expected to commence in the second quarter of 2008. Approximately 10,000 net acres in the immediate vicinity of our recent deep gas tests were excluded from the agreement and we plan to drill several wells on this acreage in 2008.

In the Green River Basin, we are active in the Pinedale and Jonah fields. We plan to drill 10 wells at Pinedale in 2008. Through an agreement reached in 2007, we assumed operatorship of the drilling program and increased our working interest to 85%. In the Jonah field, we are planning to drill five wells in 2008.

For 2008, we plan to drill at least 10 wells and invest approximately $50 million in the Williston Basin, including seismic purchases. Prospective targets in this region include the Madison, Red River and Duperow formations.

Onshore Texas. As of December 31, 2007, we owned an interest in approximately 350,000 gross acres and about 650 gross producing wells onshore Texas.

We are active in most of the major producing trends in South Texas, including the Frio, Wilcox and Lobo plays. Our largest investment in South Texas in 2008 will be the Frio Trend. We have an interest in more than 60,000 acres in this trend, which is located primarily in Kenedy, Hidalgo, Brooks and Zapata Counties. In East Texas, we have an interest in 30,000 net acres, of which 11,000 net acres are associated with a joint venture with a private company.

To date, we have been very successful in a joint venture in Kenedy County with ExxonMobil adjacent to our existing Sarita field. Since the formation of the joint venture in 2005, we have drilled 23 successful wells and have a similar inventory of drilling locations. The area of activity today encompasses about 2,700 gross acres. The prospective horizons are numerous and gas is prevalent from 10,000 feet to as deep as 20,000 feet. Production at year-end 2007 was approximately 75 MMcfe/d gross. Our interest in the joint venture is approximately 50%.

In 2007, we formed a 40,000-acre joint venture with a private company that covers lands south and east of our existing ExxonMobil joint venture and also targets Frio horizons. Drilling is planned to begin in early 2008.

In the Val Verde Basin, we have an interest in nearly 130,000 gross acres located primarily in Val Verde, Terrell and Edwards Counties. At year-end 2007, our gross production from the area was approximately 70 MMcfe/d. Our working interests range from 50-100%. We plan to drill 10 12 wells in the basin in 2008.

Gulf of Mexico. Our activities in the Gulf of Mexico are primarily focused on deepwater. At year-end 2007, our net daily production from the deepwater was nearly 40 MMcfe/d from four fields. As of December 31, 2007, we owned interests in 61 leases in deepwater (approximately 300,000 gross acres). We also own interests in 26 conventional shallow water lease blocks and a 10 25% interest in 85 shallow water lease blocks related to the ultra deep Treasure Project concept.

In the deepwater Gulf of Mexico, we have been active in recent lease sales and expect to continue this effort in 2008. We now have an inventory of prospects that will allow us to drill four or five exploratory wells per year over the next several years. We have two field developments underway in deepwater that will grow our production in the second half of 2008 and early 2009.

Our exploration efforts in deepwater can be classified into two distinct categories prospects near existing infrastructure and those requiring stand-alone developments. The prospects located near 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 50 70%. Stand-alone developments are generally in deeper water (greater than 5,500 feet) and typically have long lead times. We often manage our exposure to these higher risk prospects by taking a smaller working interest or selling down our interest on a promoted basis.

International. Our activities are focused primarily offshore Malaysia and China. We plan to invest $155 million in international activities in 2008, of which approximately 60% is dedicated to the ongoing development of oil fields offshore Malaysia.

Our shallow water concessions in Malaysia include a 50% non-operated interest in PM 318 and a 60% operated interest in PM 323. On PM 318, our Abu field commenced production in 2007 and production at year-end 2007 was approximately 14,000 BOPD gross. Our Puteri field is expected to commence production in the second quarter of 2008 and is expected to produce 6,000 8,000 BOPD gross. We have additional fields that will be developed and produced through existing infrastructure on this 414,000 acre concession. On PM 323, we are developing the East Belumut and Chermingat fields. First production is expected in mid-2008. These fields are expected to produce about 15,000 BOPD gross. We have additional exploration prospects on this 320,000 acre concession.

On deepwater Block 2C offshore Sarawak, which covers 1.1 million acres, we plan to drill our second commitment well in the second half of 2008. We will operate the exploratory well with a 40% interest.

In China, we are producing approximately 1,200 BOPD net from Bohai Bay. We also signed agreements with respect to three new blocks in the South China Sea that cover approximately 3.5 million gross acres. At year-end 2007, we were in the process of drilling two consecutive exploration wells on these concessions.

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

Please see the discussion under the caption Forward-Looking Information in Item 7 of this report.

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.

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 deepwater 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 15, 2008, we had 927 employees. All but 76 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.

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Item 1A. *Risk Factors*

An investment in our securities involves risks. 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. 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. In addition, lower prices may reduce the amount of oil and gas that we can economically produce.

Among the factors that can cause fluctuations 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.

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. Our 2008 capital budget exceeds currently expected cash flow from operations and cash and short-term investments on hand at year end 2007 by approximately $260 million. In the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We anticipate that the shortfall will be made up with cash and short-term investments 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. We also currently expect that our 2009 capital budget will exceed expected cash flow from operations. 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 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.

Our use of oil and gas price hedging contracts involves credit risk and may limit future revenues from price increases. 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 addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices for natural gas and those of our physical pricing points. In the case of acquisitions, we may hedge acquired production for a longer period. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. While 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 the counterparty may be unable to satisfy its obligations.

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.

If oil and gas prices decrease, we may be required to take writedowns. We may be required to writedown the net capitalized costs of our oil and gas properties when oil and gas prices decrease or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs or deterioration in our exploitation results.

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. 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 is 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. Once recorded, a writedown of oil and gas properties is not reversible at a later date even if oil and gas prices increase.

Production growth at Monument Butte may be limited by the demand for our crude oil production. The crude oil produced in the Uinta Basin is known as black wax because it has a higher paraffin content than crude oil found in most other major North American basins. Due to its waxy composition, the oil is transported by truck to refiners in the Salt Lake City area. These refiners have limited capacity to refine this type of crude. We currently have agreements in place with four area refiners that secure base load capacity of approximately 14,000 BOPD through 2008 and 12,500

BOPD through 2009. We are working with the refiners to secure additional capacity to allow for continued production growth. Without additional refining capacity, our ability to increase production from the field may be limited.

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. Competition for these professionals is extremely intense. We are likely to continue to experience increased costs to attract and retain these professionals.

Competition for available oil and gas properties is extremely intense. 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. Recently, higher commodity prices and stiff competition for acquisitions have significantly increased the cost of available properties.

We may be unable to obtain the drilling rigs or support services necessary for our offshore drilling and development programs in a timely manner or at acceptable rates. In periods of increased drilling activity resulting from high commodity prices, demand exceeds availability for offshore drilling rigs, drilling vessels, dive boats, supply boats and experienced personnel. The market for oilfield services is currently very competitive. This may lead to difficulty and delays in consistently obtaining services and equipment from vendors, obtaining drilling rigs and other equipment at acceptable rates, and scheduling equipment fabrication at factories and fabrication yards. This, in turn, may lead to projects being delayed or increased costs.

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.

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

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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 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 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 can cause substantial damage to facilities and interrupt production. Some of our offshore operations are dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. Necessary infrastructures may be temporarily unavailable due to adverse weather conditions or may not be available to us in the future.

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 may involve significant financial risks. 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 offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel.

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;
- 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.

We have risks associated with our foreign operations. Ownership of property interests and production operations in areas outside the United States is subject to the various risks inherent in foreign 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 foreign-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 foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts of the United States.

Our certificate of incorporation, bylaws, stockholder rights plan and some of our arrangements with employees contain provisions that could discourage an acquisition or change of control of our company. Our stockholder rights plan, together with certain provisions of our certificate of incorporation and bylaws, 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. 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-2007, 96% of our proved reserves were located in the U.S. and 92% were located onshore. Our 10 largest fields or plays accounted for approximately 77% of our proved reserves at year-end 2007. The largest of those, the Woodford Shale play and the Monument Butte field accounted for about 43% of our proved reserves and around 36% of the net present value of our proved reserves at December 31, 2007.

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, 2007.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
United States:			
Oil and condensate (MMBbls)	61	34	95
Gas (Bcf)	1,136	674	1,810
Total proved reserves (Bcfe)	1,505	876	2,381
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 4,033
International:			
Oil and condensate (MMBbls)	10	9	19
Gas (Bcf)			
Total proved reserves (Bcfe)	61	54	115
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 498
Total:			
Oil and condensate (MMBbls)	71	43	114
Gas (Bcf)	1,136	674	1,810
Total proved reserves (Bcfe)	1,566	930	2,496
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 4,531

(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 $5.88 per Mcf for gas and $85.33 per Bbl for oil. This calculation does not include the effects of hedging. For a further description of how this measure is determined, see Supplementary Financial Information Supplementary Oil and Gas Disclosures Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves.

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.

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Drilling Activity

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

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
United States:						
Productive(1)	343	219.0	420	290.5	390	296.3
Nonproductive(2)	24	16.6	36	21.1	32	23.3
Malaysia:						
Productive(3)	1	0.6	10	4.9	4	2.0
Nonproductive(4)	3	2.1	3	1.6	2	1.0
International Total:						
Productive	1	0.6	10	4.9	4	2.0
Nonproductive	3	2.1	3	1.6	2	1.0
Exploratory well total	371	238.3	469	318.1	428	322.6
Development wells:						
United States:						
Productive	135	105.7	199	183.2	135	116.1
Nonproductive	2	1.6	3	2.7	1	1.0
China:						
Productive	8	1.0	14	1.7		
Nonproductive						
Malaysia:						
Productive	3	1.7				
Nonproductive						
International Total:						
Productive	11	2.7	14	1.7		
Nonproductive						
Development well total	148	110.0	216	187.6	136	117.1

(1) Includes 19 gross (12 net), 62 gross (52.6 net) and 27 gross (17.5 net) wells in 2007, 2006 and 2005, respectively, that are not exploitation wells.

(2) Includes 15 gross (8.8 net), 16 gross (10.8 net) and 16 gross (10.0 net) wells in 2007, 2006 and 2005, respectively, that are not exploitation wells.

(3)

Includes 2 gross (0.9 net) and 1 gross (0.5 net) wells in 2006 and 2005, respectively, that are not exploitation wells.

(4) Includes 3 gross (2.1 net), 2 gross (1.1 net) and 2 gross (1.0 net) wells in 2007, 2006 and 2005, respectively, that are not exploitation wells.

We were in the process of drilling 61 gross (36.5 net) exploratory wells (includes 58 gross (35.2 net) exploitation wells) and eight gross (3.7 net) development wells in the United States and one gross (1.0 net) exploratory well in China at December 31, 2007.

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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, 2007 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
United States:						
Gulf of Mexico:						
Oil			2	0.5	2	0.5
Gas	1	0.5	1	0.3	2	0.8
Montana:						
Oil	70	55.7	29	7.3	99	63.0
Gas						
North Dakota:						
Oil	18	12.8	49	3.7	67	16.5
Gas			1		1	
Oklahoma:						
Oil	302	223.0	589	21.9	891	244.9
Gas	631	479.0	786	134.7	1,417	613.7
Texas:						
Oil	30	25.0	18	5.3	48	30.3
Gas	549	493.6	280	112.5	829	606.1
Utah:						
Oil	1,443	1,197.7	15	3.2	1,458	1,200.9
Gas	15	10.3	1	0.1	16	10.4
Wyoming:						
Oil	101	90.1	11	2.0	112	92.1
Gas	35	21.6	48	10.6	83	32.2
Other domestic:						
Oil			1	0.3	1	0.3
Gas	11	7.5	34	7.0	45	14.5
Total domestic:						
Oil	1,964	1,604.3	714	44.2	2,678	1,648.5
Gas	1,242	1,012.5	1,151	265.2	2,393	1,277.7
International:						
Offshore China:						
Oil			22	2.6	22	2.6
Offshore Malaysia:						
Oil	3	1.8	19	9.5	22	11.3
Total international:						

Oil	3	1.8	41	12.1	44	13.9
Total:						
Oil	1,967	1,606.1	755	56.3	2,722	1,662.4
Gas	1,242	1,012.5	1,151	265.2	2,393	1,277.7
Total	3,209	2,618.6	1,906	321.5	5,115	2,940.1

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements or production sharing contracts. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. Generally, an operator receives reimbursement for direct expenses incurred in the performance of its duties as well as

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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, 2007, 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)			
United States:				
Gulf of Mexico:				
Deepwater	52	11	248	128
Shelf	30	6	95	40
Treasure Project			449	52
Total Gulf of Mexico	82	17	792	220
Onshore:				
Colorado			83	43
Montana	31	24	429	331
North Dakota	13	6	139	90
Oklahoma	534	287	212	93
South Dakota			14	5
Texas	169	105	183	120
Utah	60	51	236	187
Wyoming	18	12	150	84
Other domestic	15	6	92	91
Total onshore	840	491	1,538	1,044
Total domestic	922	508	2,330	1,264
International:				
Offshore Brazil			121	121
Offshore China	22	3	3,558	3,558
Offshore Malaysia	99	50	1,752	939
Total international	121	53	5,431	4,618
Total	1,043	561	7,761	5,882

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 359,005 gross (101,925 net) undeveloped acres. These interests do not expire.

	Undeveloped Acres Expiring									
	2008		2009		2010		2011		2012	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(In thousands)									
United States:										
Gulf of Mexico:										
Deepwater	6	1	6	4	40	14	17	13	40	10
Shelf	27	11	16	8	15	8	10	4	5	5
Treasure Project	263	27	57	6	41	5	5	1	12	1
Total Gulf of Mexico	296	39	79	18	96	27	32	18	57	16
Onshore:										
Montana	21	21	8	8	273	186	88	39	7	4
Oklahoma	43	29	28	24	46	30	1	1		
Texas	68	46	54	41	18	14	6	2	6	4
Utah	7	7	6	3	3	2	4	2	7	4
Other domestic	26	22	35	33	74	36	68	68		
Total onshore	165	125	131	109	414	268	167	112	20	12
Total domestic	461	164	210	127	510	295	199	130	77	28
International:										
Offshore Brazil										
Offshore China			439	439	450	450				
Offshore Malaysia			336	336	338	196	1,079	575		
Total international			775	775	788	646	1,079	575		
Total	461	164	985	902	1,298	941	1,278	705	77	28

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. 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*

In December 2002, a lawsuit against our Mid-Continent subsidiary was filed in Beaver County, Oklahoma and was later certified as a class action royalty owner lawsuit. The complaint alleged that we improperly reduced royalty payments for certain expenses and charges, and also claimed breach of contract and breach of fiduciary duties, among other claims. In April 2007, we entered into a settlement agreement that has since received court approval.

We also have been named as a defendant in a number of other lawsuits that arose in the ordinary course of our business. While the outcome of these lawsuits 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.

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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 2007.

Item 4A. ***Executive Officers of the Registrant***

The following table sets forth the names and ages (as of February 29, 2008) 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	59	Chairman, President & Chief Executive Officer and a Director	13
Lee K. Boothby	46	Senior Vice President Acquisitions & Business Development	8
Terry W. Rathert	55	Senior Vice President, Chief Financial Officer & Secretary	18
Michael D. Van Horn	56	Senior Vice President Exploration	1
Mona Leigh Bernhardt	41	Vice President Human Resources	8
W. Mark Blumenshine	49	Vice President Land	6
Stephen C. Campbell	39	Vice President Investor Relations	8
George T. Dunn	50	Vice President Mid-Continent	15
John H. Jasek	38	Vice President Gulf Coast	7
James J. Metcalf	50	Vice President Drilling	12
Gary D. Packer	45	Vice President Rocky Mountains	12
William D. Schneider	56	Vice President International	18
Mark J. Spicer	48	Vice President Information Technology	7
James T. Zernell	50	Vice President Production	11
John D. Marziotti	44	General Counsel	4
Brian L. Rickmers	39	Controller & Assistant Secretary	14
Susan G. Riggs	50	Treasurer	11

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

David A. Trice reassumed the role of President in October 2007. He was appointed Chairman in September 2004.

Lee K. Boothby was promoted to his present position in 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.

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.

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John H. Jasek was named Vice President Gulf Coast in October 2007 and became the manager of our onshore Gulf Coast operations. He has managed our Gulf of Mexico operations since March 2005, 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 a Gulf of Mexico General Manager to Vice President Rocky Mountains in November 2004.

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. 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***

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
2006		
First Quarter	54.50	35.07
Second Quarter	51.75	38.65
Third Quarter	49.72	34.99
Fourth Quarter	50.16	34.90
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 (through February 25, 2008)	54.98	44.15

On February 25, 2008, the last reported sales price of our common stock on the NYSE was $53.20 per share. As of that date, there were approximately 1,885 holders of record of our common stock.

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 could restrict our ability to pay cash dividends.

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2007.

	Total Number of Shares	Average Price	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number (or Approximate) Dollar Value) of Shares that May Yet be Purchased Under

Period	Purchased(1)	Paid per Share	or Programs	the Plans or Programs
October 1 October 31, 2007	1,577	$ 51.54		
November 1 November 30, 2007	2,645	$ 49.78		
December 1 December 31, 2007	529	$ 53.75		

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

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Item 5A. *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, 2002 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 is comprised 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	**12/31/2002**	**12/31/2003**	**12/31/2004**	**12/31/2005**	**12/31/2006**	**12/31/2007**
Newfield Exploration	$ 100.00	$ 123.52	$ 163.78	$ 277.70	$ 254.85	$ 292.29
Peer Group	$ 100.00	$ 133.98	$ 179.62	$ 284.78	$ 280.57	$ 423.68
S&P 500	$ 100.00	$ 128.63	$ 142.59	$ 149.58	$ 173.01	$ 182.40

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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,				
	2007	2006	2005	2004	2003
	(In millions, except per share data)				
Income Statement Data:					
Oil and gas revenues	$ 1,783	$ 1,673	$ 1,762	$ 1,350	$ 1,017
Income from continuing operations	172	610	342	331	211
Net income	450	591	348	312	200
Earnings per share:					
Basic					
Income from continuing operations	1.35	4.82	2.73	2.84	1.94
Net income	3.52	4.67	2.78	2.68	1.83
Diluted					
Income from continuing operations	1.32	4.73	2.68	2.79	1.88
Net income	3.44	4.58	2.73	2.63	1.78
Weighted average number of shares outstanding for basic earnings per share	128	127	125	117	109
Weighted average number of shares outstanding for diluted earnings per share	131	129	128	119	113
Cash Flow Data:					
Net cash provided by continuing operating activities	$ 1,166	$ 1,392	$ 1,119	$ 1,006	$ 660
Net cash used in continuing investing activities	(865)	(1,552)	(1,015)	(1,584)	(606)
Net cash provided by (used in) continuing financing activities	(117)	174	(124)	613	(85)
Balance Sheet Data (at end of period):					
Total assets	$ 6,986	$ 6,635	$ 5,081	$ 4,327	$ 2,733
Long-term debt	1,050	1,048	870	992	643
Reserve Data (at end of period):					
Proved reserves:					
Oil and condensate (MMBbls)	114	114	102	91	38
Gas (Bcf)	1,810	1,586	1,391	1,241	1,090
Total proved reserves (Bcfe)	2,496	2,272	2,001	1,784	1,317
Present value of estimated future after-tax net cash flows	$ 4,531	$ 3,447	$ 5,053	$ 3,602	$ 2,935

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. 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.

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 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. 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 value of our derivative positions; and
- the fair value of stock-based compensation.

Accounting for Hedging Activities. Beginning October 1, 2005, we elected not to designate any future 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. Please see Critical Accounting Policies and Estimates *Commodity Derivative Activities*.

Results of Operations

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

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.

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 September 2007, we sold our coal bed methane assets in the Cherokee Basin of northeastern Oklahoma for $128 million in cash.

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 subsidiaries are reflected in our financial statements as discontinued operations. This reclassification affects not only the 2007 presentation of our financial statements, but also the presentation of all prior period financial statements. Except where noted, discussions in this report relate to continuing operations only.

Please see Note 3, Discontinued Operations, and Note 4, Oil and Gas Assets, 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 revenues, but those not so designated have no effect on our reported revenues. None of our outstanding hedges are designated for hedge accounting. 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 $1.8 billion for 2007 were 7% higher than 2006 revenues due to higher oil production and higher oil prices partially offset by lower gas production and lower gas prices. Revenues of $1.7 billion for 2006 were 5% lower than 2005 revenues due to lower gas prices and oil production partially offset by higher oil prices and increased gas production.

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	Year Ended December 31,		
	2007	**2006**	**2005**
Production[1]:			
United States:			
Natural gas (Bcf)	192.8	198.7	190.9
Oil and condensate (MBbls)	6,501	6,218	7,152
Total (Bcfe)	231.8	236.0	233.7
International:			
Natural gas (Bcf)			
Oil and condensate (MBbls)	2,258	1,097	1,294
Total (Bcfe)	13.5	6.6	7.8
Total:			
Natural gas (Bcf)	192.8	198.7	190.9
Oil and condensate (MBbls)	8,759	7,315	8,446
Total (Bcfe)	245.3	242.6	241.5
Average Realized Prices[2]:			
United States:			
Natural gas (per Mcf)	$ 6.33	$ 6.47	$ 7.18
Oil and condensate (per Bbl)	61.32	51.40	44.06
Natural gas equivalent (per Mcfe)	6.98	6.80	7.21
International:			
Natural gas (per Mcf)	$	$	$
Oil and condensate (per Bbl)	69.21	56.58	55.68
Natural gas equivalent (per Mcfe)	11.53	9.43	9.28
Total:			
Natural gas (per Mcf)	$ 6.33	$ 6.47	$ 7.18
Oil and condensate (per Bbl)	63.35	52.18	45.84
Natural gas equivalent (per Mcfe)	7.23	6.87	7.27

(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 $7.62, $7.22 and $6.65 per Mcf for 2007, 2006 and 2005, respectively. Our total oil and condensate average realized price would have been $55.04, $50.25 and $44.36 per Bbl for 2007, 2006 and 2005, respectively. Without the effects of any hedging contracts, our average realized prices for 2007, 2006 and 2005 would have been $6.33, $6.42 and $7.54 per Mcf, respectively, for gas and $64.12, $59.13 and $53.36 per barrel, respectively, for oil.

Domestic Production. 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% primarily as a result of the sale of our shallow water Gulf of Mexico assets in August 2007. This decrease was 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 acquisition there in June 2007. Our 2006 Gulf of Mexico production was negatively impacted (16 Bcfe) by production deferrals related to Hurricanes Katrina and Rita in 2005. Our domestic oil and condensate production increased 5% over 2006 primarily due to increased sales from our Monument Butte field.

Our 2006 domestic gas and oil production (stated on a natural gas equivalent basis) increased slightly over 2005. Our 2006 domestic natural gas production increased 4% over 2005 primarily as the result of successful drilling efforts in the Mid-Continent partially offset by continued Gulf of Mexico production deferrals during the first half of 2006 related to the 2005 storms and natural declines in production from some fields. Our 2006 domestic oil and condensate production decreased 13% over 2005. The decrease was primarily the result of continued Gulf of Mexico production deferrals during the first half of 2006 related to the 2005 storms and natural declines in production from some fields.

International Production. Our 2007 international oil and gas production (stated on a natural gas equivalent basis) 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 in Malaysia and China. Our 2006 international oil and gas production decreased 15% from 2005 due to the timing of liftings of oil production in Malaysia.

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

Year ended December 31, 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			Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2007	2006		2007	2006	
	(Per Mcfe)			(In millions)		
United States:						
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%

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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:

Lease operating expense (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 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 depreciation, depletion and amortization (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.

General and administrative (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 storms.

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.

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

Year ended December 31, 2006 compared to December 31, 2005

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2006.

	Unit-of-Production Year Ended December 31, 2006	2005	Percentage Increase (Decrease)	Amount Year Ended December 31, 2006	2005	Percentage Increase (Decrease)
	(Per Mcfe)			(In millions)		
United States:						
Lease operating	$ 1.11	$ 0.81	37%	$ 261	$ 190	38%
Production and other taxes	0.21	0.25	(16)%	49	58	(15)%
Depreciation, depletion and amortization	2.59	2.18	19%	611	510	20%
General and administrative	0.49	0.43	14%	116	101	14%
Other	(0.04)	(0.12)	(67)%	(11)	(29)	(63)%
Total operating expenses	4.36	3.55	23%	1,026	830	24%
International:						
Lease operating	$ 2.22	$ 1.89	17%	$ 15	$ 15	
Production and other taxes	1.77	0.83	113%	12	6	81%
Depreciation, depletion and amortization	1.96	1.34	46%	13	10	24%
General and administrative	0.44	0.05	780%	2	1	644%
Ceiling test writedown	0.94	1.24	(24)%	6	10	(35)%
Total operating expenses	7.33	5.35	37%	48	42	16%
Total:						
Lease operating	$ 1.14	$ 0.85	34%	$ 276	$ 205	35%
Production and other taxes	0.25	0.26	(4)%	61	64	(5)%
Depreciation, depletion and amortization	2.57	2.15	20%	624	520	20%
General and administrative	0.48	0.42	14%	118	102	15%
Ceiling test writedown	0.03	0.04	(25)%	6	10	(35)%
Other	(0.04)	(0.12)	(67)%	(11)	(29)	(63)%
Total operating expenses	4.43	3.60	23%	1,074	872	23%

Domestic Operations. Our domestic operating expenses for 2006, stated on an Mcfe basis, increased 24% over 2005. The period to period change was primarily related to the following items:

LOE increased due to higher operating costs for all of our operations and significantly higher insurance costs for our Gulf of Mexico operations. Additionally, 2006 LOE was negatively impacted by the difference ($0.07 per Mcfe) between insurance proceeds received from the settlement of all claims related to the 2005 storms and actual repair expenditures during 2006. Without the impact of this difference, our LOE would have been $1.04 per Mcfe for 2006.

Production and other taxes decreased primarily due to refunds of $18 million ($0.07 per Mcfe) related to production tax exemptions on certain of our onshore high cost gas wells in Texas.

The increase in our DD&A rate resulted from higher cost reserve additions. The cost of reserve additions was adversely impacted by escalating costs of drilling goods and services experienced during

2006. The component of DD&A associated with accretion expense related to our asset retirement obligation was $0.06 per Mcfe for 2006 and 2005.

G&A expense increased approximately $0.06 per Mcfe primarily due to stock-based compensation expense recognized as a result of our adoption of Statement of Financial Accounting Standards (SFAS) No. 123(R) on January 1, 2006. Please see Note 10, Stock-Based Compensation, to our consolidated financial statements. The increase attributable to stock-based compensation expense was partially offset by a decrease in incentive compensation expense as a result of lower adjusted net income (as defined in our incentive compensation plan) in 2006 as compared to the prior year. Adjusted net income for purposes of our incentive compensation plan excludes unrealized gains and losses on commodity derivatives. During 2006, we capitalized $40 million ($0.17 per Mcfe) of direct internal costs as compared to $38 million ($0.17 per Mcfe) in 2005.

Other expenses for 2006 and 2005 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 storms.

In 2005, we recorded a $22 million benefit from our business interruption insurance coverage and sold our interest in the floating production system and related equipment we acquired in the EEX transaction for a net gain of $7 million.

International Operations. Our international operating expenses for 2006, stated on an Mcfe basis, increased 37% over 2005. The increase was primarily related to the following items:

LOE increased because our production in Malaysia decreased while total LOE remained relatively unchanged. Our Malaysian LOE primarily consists of fixed costs related to our FPSOs.

Production and other taxes increased as a result of higher realized crude oil prices.

The DD&A rate increased as a result of higher cost reserve additions in Malaysia and the commencement of liftings of oil production in China in August 2006.

G&A expense increased due to stock compensation expense recognized as a result of the adoption of SFAS No. 123(R) on January 1, 2006 and growth in our international workforce.

We recorded a ceiling test writedown of $6 million associated with ceasing our exploration efforts in Brazil in 2006. In 2005, we recorded a ceiling test writedown of $10 million associated with our decreased emphasis on exploration efforts in Brazil and in other non-core international regions.

Interest Expense. The following table presents information about our interest expense for each of the years in the three-year period ended December 31, 2007.

	Year Ended December 31,		
	2007	**2006**	**2005**

	(In millions)		
Gross interest expense	$ 102	$ 87	$ 72
Capitalized interest	(47)	(44)	(46)
Net interest expense	$ 55	$ 43	$ 26

The increase in gross interest expense in 2007 resulted primarily from higher average 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 the 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

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outstanding borrowings under our credit arrangements and $125 million principal amount of our 7.45% Senior Notes that became due in October 2007.

The increase in gross interest expense in 2006 resulted primarily from the April 13, 2006 issuance of $550 million principal amount of our 65/8% Senior Subordinated Notes due 2016, partially offset by the May 3, 2006 redemption of $250 million principal amount of our 83/8% Senior Subordinated Notes due 2012.

Commodity Derivative Income (Expense). The following table presents information about the components of commodity derivative income (expense) for each of the years in the three-year period ended December 31, 2007.

	Year Ended December 31,		
	2007	2006	2005
	(In millions)		
Cash flow hedges:			
Hedge ineffectiveness[1]	$	$ 5	$ (8)
Other derivative contracts:			
Realized loss on settlement of discontinued cash flow hedges[2]			(51)
Unrealized gain (loss) due to change in fair market value[3]	(365)	249	(202)
Realized gain (loss) on settlement	177	135	(61)
Total commodity derivative income (expense)	$ (188)	$ 389	$ (322)

(1) Hedge ineffectiveness is associated with our hedging contracts that qualify for hedge accounting under SFAS No. 133.

(2) In the third quarter of 2005, as a result of the production deferrals experienced in the Gulf of Mexico related to the storms, hedge accounting was discontinued on a portion of our contracts that had previously qualified as effective cash flow hedges of our Gulf of Mexico production and other contracts were redesignated as hedges of our onshore Gulf Coast production. As a result, realized losses of $51 million associated with derivative contracts for the third and fourth quarters of 2005, which were in excess of hedged physical deliveries for those periods, were reported as commodity derivative expense.

(3) The unrealized gain (loss) due to changes in fair market value is associated with our derivative contracts that are not designated for hedge accounting and represents changes in the fair value of these open contracts during the period.

Taxes. The effective tax rates for the years ended December 31, 2007, 2006 and 2005 were 41%, 36% and 37%, respectively. Our effective tax rate was more than the federal statutory tax rate for all three years primarily due to state income taxes and the differences between international and U.S. federal statutory rates. Our effective tax rate for 2007 increased because $26 million of interest income on intercompany loans to our international subsidiaries was included in the determination of U.S. federal income taxes. However, the related intercompany interest expense was incurred 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 and amount 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 production and cash flow. We accomplish this through successful drilling programs and the acquisition of properties. These activities require substantial capital expenditures. We establish a capital budget at the beginning of each calendar year. Our 2008 capital budget currently exceeds expected cash flow from operations and cash and short-term investments on hand at year end 2007 by approximately $260 million. We anticipate that the shortfall will be made up with cash and short-term investments on hand and borrowings under our credit arrangements. In the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. To the extent that we increase our capital budget during 2008, we anticipate funding these amounts with borrowings under our credit arrangements.

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Credit Arrangements. In June 2007, we entered into a new revolving credit facility that matures in June 2012 and provides for initial loan commitments of $1.25 billion from a syndicate of financial institutions, led by JPMorgan Chase as agent. The loan commitments may be increased to a maximum of $1.65 billion if the existing lenders increase their loan commitments or new financial institutions are added to the facility. 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. For a more detailed description of the terms of our credit arrangements, please see Note 8, Debt, to our consolidated financial statements appearing later in this report.

At February 28, 2008, we had no borrowings outstanding under our credit facility nor under our money market lines of credit and we had approximately $1.4 billion 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.

At December 31, 2007, we had a working capital deficit of $2 million. Our current assets include $370 million of cash and short-term investments remaining from the proceeds of property sales. 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 short-term net derivative liability of $84 million.

This compares to a working capital deficit of $272 million at the end of 2006 and $129 million at the end of 2005. The majority of the working capital deficit at December 31, 2006 relates to the reclassification of $125 million principal amount of our 7.45% Senior Notes due October 15, 2007 as a current liability and an increase in accrued liabilities as a result of our significant capital activities near the end of 2006. The increase in accrued liabilities is due to our increased exploration and development activity and higher service costs over 2005. Our 2006 working capital deficit also includes $40 million in asset retirement obligations compared to $47 million in 2005. Our 2006 working capital includes a short-term net derivative asset of $200 million and our 2005 working capital includes a short-term net derivative liability of $89 million.

Cash Flows from Operations. Cash flows from operations (both continuing and discontinued) are primarily affected by production and commodity prices, net of the effects of settlements of our derivative contracts and changes in working capital. We also have experienced fluctuations in operating cash flows as a result of higher operating costs for all of our operations and activities associated with the 2005 storms. In August 2006, we reached an agreement with our insurance underwriters to settle all claims related to the 2005 storms (business interruption, property damage and control of well/operator s extra expense) for $235 million. During 2007, we incurred $52 million of repair expenditures in excess of the insurance benefits received as compared to $17 million of uninsured repairs during 2006. These amounts are reflected as a use of operating cash flows in the respective year.

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, writedowns or other non-cash charges or credits.

Our net cash flow from operations was $1.2 billion in 2007, a decrease of 17% compared to net 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 the property sales. 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.

Our net cash flow from operations was $1.4 billion in 2006, a 25% increase over the prior year. The increase was primarily due to 2006 realized oil and gas prices (on a natural gas equivalent basis), including the effects of hedging contracts (regardless of whether designated for hedge accounting), which increased 9% over 2005. See Results of Operations above.

Cash Flows from Investing Activities. Net cash used in investing activities (both continuing and discontinued) for 2007 was $906 million compared to $1.7 billion for 2006.

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 short-term investments of $271 million and redeemed short-term investments of $172 million.

During 2006, we:

- spent $1.6 billion;
- received insurance recoveries of $45 million; and
- purchased short-term investments of $714 million and redeemed short-term investments of $690 million.

Capital Expenditures. 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.

Our 2006 capital spending of $1.7 billion increased 61% from our 2005 capital spending of $1.1 billion. These amounts exclude recorded asset retirement obligations of $11 million in 2006 and $44 million in 2005. During 2006, we invested $1.2 billion in domestic exploitation and development, $379 million in domestic exploration (exclusive of exploitation and leasehold activity), $71 million in other domestic leasehold activity and $133 million internationally.

We budgeted $1.6 billion for capital spending in 2008, excluding acquisitions and $113 million of estimated capitalized interest and overhead. Approximately 40% of the $1.6 billion is allocated to the Mid-Continent, 20% to the Rocky Mountains, 15% to the onshore Gulf Coast, 15% to the Gulf of Mexico and 10% to international projects. See Item 1, *Business* Our Properties and Plans for 2008. Since our 2008 capital budget currently exceeds forecasted net cash flow from operations, we plan to make up the shortfall with cash and short-term investments on hand and borrowings under our credit arrangements. Actual levels of capital expenditures may vary significantly due to many factors, including the extent to which properties are acquired, drilling results, oil and gas prices, industry conditions and the prices and availability of goods and services. We continue to pursue attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. Depending on the timing of an acquisition, we may spend additional capital during the year of the acquisition for drilling and development activities on the acquired properties.

Cash Flows from Financing Activities. Net cash flow used in financing activities (both continuing and discontinued) for 2007 was $79 million compared to $317 million of net cash flow provided by financing activities for 2006.

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.

During 2006, we:

issued $550 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2016;

used the proceeds from the notes to redeem $250 million principal amount of our 83/8% Senior Subordinated Notes due 2012;

borrowed and repaid $519 million under our credit arrangements;

received proceeds of $15 million from the issuance of shares of our common stock upon the exercise of stock options; and

received a $5 million tax benefit from the exercise of stock options.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of December 31, 2007.

	Total	Less Than 1 Year	2-3 Years	4-5 Years	More Than 5 Years
			(In millions)		
Debt:					
Revolving credit facility	$	$	$	$	$
Money market lines of credit					
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
Total debt	1,050			175	875
Other obligations:					
Interest payments	506	71	143	122	170

Net derivative liabilities (assets)	315	84	233	(2)	
Asset retirement obligations	62	6	4	8	44
Operating leases	241	122	89	11	19
Deferred acquisition payments	9	3	4	2	
Oil and gas activities[1]	7				
Total other obligations	1,140	286	473	141	233
Total contractual obligations	$ 2,190	$ 286	$ 473	$ 316	$ 1,108

(1) 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 and fulfilling other cash commitments. At December 31, 2007, these work related commitments totaled $7 million and were comprised of $3 million in the United States and $4 million internationally. These 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.

During the third quarter of 2003, we entered into interest rate swap agreements that provide for us to pay variable and receive fixed interest payments and are designated as fair value hedges of a portion of our senior notes (see Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* and Note 8, Debt *Interest Rate Swaps*, 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. 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.

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

incur additional debt;

make restricted payments;

pay dividends on or redeem our capital stock;

make certain investments;

create liens;

engage in transactions with affiliates; and

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

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

Oil and Gas Hedging

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and 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 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 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. Approximately 87% of our 2007 production was subject to derivative contracts (including basis contracts). In 2006, 57% of our production was subject to derivative contracts, compared to 81% in 2005.

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. 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 the 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 less per MMBtu than the Henry Hub Index. Realized gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average 75-85% of the Henry Hub Index. In light of potential basis risk with respect to our newly acquired Rocky Mountain assets, we have hedged the basis differential for about 50% of our estimated production from proved producing fields acquired from Stone Energy through 2012 to lock in the differential at a weighted average of $1.18 per MMBtu less than the Henry Hub Index. The price we receive for our Gulf Coast oil production typically averages about $2 per barrel below the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains is currently averaging about $13-$15 per barrel below the WTI price. Oil production from the Mid-Continent typically sells at a $1.00-$1.50 per barrel discount to WTI. Oil sales from our operations in Malaysia typically sell at Tapis, which generally is consistent with WTI. Oil sales from our operations in China typically sell at $10-$12 per barrel less than WTI.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. At December 31, 2007, Barclays Capital, JPMorgan Chase, Citibank N.A., J Aron & Company, Bank of Montreal and Credit Suisse were the counterparties with respect to 84% of our future hedged production.

Between January 1, 2008 and February 25, 2008, we entered into the additional derivative contracts set forth below. None of these contracts have been designated for hedge accounting.

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Natural Gas

		NYMEX Contract Price per MMBtu							
					Collars				
		Swaps	Additional Put		Floors		Ceilings		
e of Contract	Volume in MMMBtus	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	Rang
2008									
	5,460								$8.58-$
mber 2008									
	5,520								8.58-
ecember 2008									
acts	610	$9.00							
	2,440				$8.00	$8.00	$10.20-$10.70	$10.38	
	1,860								8.58-
ntracts	4,880		$7.00-$7.50	$7.19	8.00-9.00	8.63	11.72-13.80	12.95	
ecember 2009									
acts	8,390	8.47							
	5,740				8.00	8.00	8.97-10.70	9.86	
ntracts	7,200		7.00-7.50	7.19	8.00-9.00	8.63	11.72-13.80	12.95	

In addition, in February 2008 we paid $14.6 million to unwind and rehedge 360 MBbls of our oil contracts for January 2010 through December 2010. The three-way collar contracts that we unwound had weighted average prices of $32.00 and $50.88 per barrel for the floor and ceiling prices, respectively. These contracts had an additional put with a weighted average price of $25.00 per barrel. We rehedged these barrels for this period with a weighted average swap price of $93.40 per barrel.

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 and a listing of open contracts as of December 31, 2007 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 value of the assets and liabilities of the acquired company.

Accounting for commodity derivative activities requires estimates and assumptions regarding the 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 2007 would have required a decrease in our estimated proved reserves at December 31, 2006 of approximately 13 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 6% of our consolidated production for 2007, 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. 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 decline, or if we have downward revisions to our estimated proved reserves, it is possible that writedowns of our oil and gas properties could occur in the future.

At December 31, 2007, the ceiling value of our domestic oil and gas reserves was calculated based upon quoted market prices of $6.80 per MMBtu for gas and $96.01 per barrel for oil, adjusted for market differentials. Using these prices, the ceiling exceeded the net capitalized costs of our domestic oil and gas properties by approximately $1.9 billion (net of tax) at December 31, 2007.

At December 31, 2007, the ceiling with respect to our oil and gas properties in Malaysia and China exceeded the net capitalized costs of the properties by approximately $117 million and $70 million, respectively. Holding all other factors constant, if the applicable index for oil prices were to decline to approximately $70 per Bbl, it is possible that we could experience a ceiling test writedown in Malaysia. It is possible that we could experience a ceiling test writedown in China if the applicable index for oil prices were to decline to approximately $55 per Bbl, holding all other factors constant.

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, 2007, our domestic full cost pool had approximately $1.1 billion of costs excluded from the amortization base. Because the application of the full cost ceiling test at December 31, 2007 resulted in a significant excess of the cost-center ceiling over the carrying value of our domestic oil and gas properties, inclusion of some or all of our unevaluated property costs in our amortization base, without adding any associated reserves, would not have resulted in a ceiling test writedown. However, our future DD&A rate would increase to the extent such costs are transferred without any associated reserves.

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, 2007 would require an increase in the present value of our estimated future development and abandonment costs at December 31, 2006 of approximately $38 million. Due to the relatively small size of our international full cost pools in Malaysia and China, a change greater than $30 million and $9 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 6% of our consolidated production for 2007, a change in our international DD&A expense would not have materially affected our consolidated results of operations.

Allocation of Purchase Price in Business Combinations. As part of our growth strategy, we actively pursue 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

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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 will change in 2009. Please see New Accounting Standards below for a detailed discussion.

Goodwill of each reporting unit (each country is a separate reporting unit) is tested for impairment on an annual basis, or more frequently if an event occurs or circumstances change that would reduce the fair value of the reporting unit below its carrying amount. In making this assessment, we rely on a number of factors including operating results, business plans, economic projections and anticipated cash flows. As there are inherent uncertainties related to these factors and our judgment in applying them to the analysis of goodwill impairment, there is risk that the carrying value of our goodwill may be overstated. If it is overstated, such impairment would reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill. We elected to make December 31 our annual assessment date.

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. To the extent that changes in the fair values of the cash flow hedges offset changes in the expected cash flows from our forecasted production, such amounts are not included in our consolidated results of operations. Instead, they are recorded directly to stockholders equity until the hedged oil or natural gas quantities are produced and sold. To the extent that changes in the fair values of the derivative exceed the changes in the expected cash flows from the forecasted production, the changes are recorded in income in the period in which they occur. Derivatives that do not qualify or have not been designated as cash flow hedges for hedge accounting are carried at their fair value on our consolidated balance sheet. We recognize all changes in the fair value of these contracts on our consolidated statement of income in the period in which the changes occur. 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.

In determining the amounts to be recorded for our open hedge contracts, we are required to estimate the fair value of the derivative. Our estimates are based upon various factors that include closing prices on the NYMEX, over-the-counter quotations, volatility and the time value of options. 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.

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 10, 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 granted a one-year deferral of the effective date of this statement 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 goodwill impairment). This statement 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 will adopt the provisions of this statement for all recurring measures of financial assets and liabilities on January 1, 2008. We have completed our initial evaluation of the impact of SFAS No. 157 as it relates to our financial assets and liabilities 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. An entity may not apply it before that date.

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.

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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.

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (2005 EPA). This comprehensive act contains many provisions that will encourage oil and gas exploration and development in the U.S. The 2005 EPA directs the FERC, MMS and other federal agencies to issue regulations that will further the goals set out in the 2005 EPA. The 2005 EPA also increased civil and criminal penalties for any violations of the NGA, the Natural Gas Policy Act of 1978, and any rules, regulations or orders of the FERC up to $1 million per day per violation. The FERC issued a final rule effective January 26, 2006 that makes it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to the FERC s jurisdiction, to defraud, make an untrue statement or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud. These changes resulting from the 2005 EPA have significantly expanded and strengthened oversight of natural gas markets. We believe, however, that neither the 2005 EPA nor the regulations promulgated, or to be promulgated, 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.

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 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 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

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have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of such bonds or other surety can be substantial and there is no assurance that bonds or other surety can be obtained in all cases. We are currently exempt from the supplemental bonding requirements of the MMS. Under certain circumstances, the BLM or the MMS, as applicable, may require that our operations on federal leases be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations.

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

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

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

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. Actual results may vary significantly from those anticipated due to many factors, including:

- drilling results;
- oil and gas prices;
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- the availability of refining capacity for the crude oil we produce from our Monument Butte field;
- the availability of capital resources;
- labor conditions;
- severe weather conditions (such as hurricanes); and
- the other factors affecting our business described above under the caption Risk Factors.

All written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by such factors.

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.

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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 2005, 2006 and 2007 and expect to drill in 2008 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.

Farm-in or farm-out. An agreement whereunder the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in, while the interest transferred by the assignor is a farm-out.

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.

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.

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.

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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.

Promoted drilling. An agreement where under the owner of this type of interest in the drilling of a well incurs a disproportionate share of costs associated with the well until the well is drilled and completed.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

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 developed nonproducing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

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.

Waterflood. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

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.

Workover. Operations on a producing well to restore or increase 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 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 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 may also limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions.

Interest Rates

At December 31, 2007, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Bank revolving credit facility	$	$
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	
Total current and long-term debt	$ 1,000	$ 50

(1) $50 million principal amount of our 75/8% Senior Notes due 2011 is subject to interest rate swaps. These swaps provide for us to pay variable and receive fixed interest payments, and are designated as fair value hedges of a portion of our outstanding senior notes.

We consider our interest rate exposure to be minimal because a substantial majority, about 95%, of our long-term debt obligations, after taking into account our interest rate swap agreements, were at fixed rates.

Foreign Currency Exchange Rates

The functional currency for all of our foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country s functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at December 31, 2007.

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, 2007.

The effectiveness of our internal control over financial reporting as of December 31, 2007 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

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

Houston, Texas
February 29, 2008

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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for stock-based compensation effective January 1, 2006 in conjunction with the Company s adoption of SFAS No. 123(R), *Share-Based Payment*.

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 29, 2008

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NEWFIELD EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEET
(In millions, except share data)

	December 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 250	$ 80
Short-term investments	120	10
Accounts receivable	332	374
Inventories	82	44
Derivative assets	72	280
Deferred taxes	35	
Other current assets	36	58
Assets of discontinued operations		5
Total current assets	927	851
Oil and gas properties (full cost method, of which $1,189 and $970 were excluded from amortization at December 31, 2007 and December 31, 2006, respectively)	9,791	8,689
Less accumulated depreciation, depletion and amortization	(3,868)	(3,234)
	5,923	5,455
Furniture, fixtures and equipment, net	35	28
Derivative assets	17	19
Other assets	22	20
Goodwill	62	62
Assets of discontinued operations		200
Total assets	$ 6,986	$ 6,635
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 52	$ 58
Current debt		124
Accrued liabilities	671	641
Advances from joint owners	44	90
Asset retirement obligation	6	40
Derivative liabilities	156	80
Deferred taxes		63
Liabilities of discontinued operations		27

Total current liabilities	929	1,123
Other liabilities	18	28
Derivative liabilities	248	179
Long-term debt	1,050	1,048
Asset retirement obligation	56	225
Deferred taxes	1,104	963
Liabilities of discontinued operations		7
Total long-term liabilities	2,476	2,450
Commitments and contingencies (Note 13)		
Stockholders equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)		
Common stock ($0.01 par value, 200,000,000 shares authorized at December 31, 2007 and 2006; 133,232,197 and 131,063,555 shares issued at December 31, 2007 and 2006, respectively)	1	1
Additional paid-in capital	1,278	1,198
Treasury stock (at cost, 1,896,286 and 1,879,874 shares at December 31, 2007 and 2006, respectively)	(32)	(30)
Accumulated other comprehensive income (loss):		
Foreign currency translation adjustment		14
Commodity derivatives		(5)
Minimum pension liability	(3)	(3)
Retained earnings	2,337	1,887
Total stockholders equity	3,581	3,062
Total liabilities and stockholders equity	$ 6,986	$ 6,635

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

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NEWFIELD EXPLORATION COMPANY

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

	Year Ended December 31, 2007	2006	2005
Oil and gas revenues	$ 1,783	$ 1,673	$ 1,762
Operating expenses:			
Lease operating	314	276	205
Production and other taxes	101	61	64
Depreciation, depletion and amortization	682	624	520
General and administrative	155	118	102
Ceiling test writedown		6	10
Other		(11)	(29)
Total operating expenses	1,252	1,074	872
Income from operations	531	599	890
Other income (expense):			
Interest expense	(102)	(87)	(72)
Capitalized interest	47	44	46
Commodity derivative income (expense)	(188)	389	(322)
Other	6	11	3
	(237)	357	(345)
Income from continuing operations before income taxes	294	956	545
Income tax provision:			
Current	92	30	69
Deferred	30	316	134
	122	346	203
Income from continuing operations	172	610	342
Income (loss) from discontinued operations, net of tax	278	(19)	6
Net income	$ 450	$ 591	$ 348
Earnings per share:			
Basic			
Income from continuing operations	$ 1.35	$ 4.82	$ 2.73
Income (loss) from discontinued operations	2.17	(0.15)	0.05

Net income	$ 3.52	$ 4.67	$ 2.78
Diluted			
Income from continuing operations	$ 1.32	$ 4.73	$ 2.68
Income (loss) from discontinued operations	2.12	(0.15)	0.05
Net income	$ 3.44	$ 4.58	$ 2.73
Weighted average number of shares outstanding for basic earnings per share	128	127	125
Weighted average number of shares outstanding for diluted earnings per share	131	129	128

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

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
(In millions)

	Common Stock		Treasury Stock		Additional Paid-in Capital	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
	Shares	**Amount**	**Shares**	**Amount**					
Balance, December 31, 2004	126.6	$ 1	(1.8)	$ (27)	$ 1,102	$ (10)	$ 948	$ 3	$ 2,017
Issuance of common stock	2.1				33				33
Issuance of restricted stock, less amortization and cancellations	0.7				34	(26)			8
Amortization of stock compensation						2			2
Tax benefit from exercise of stock options					17				17
Comprehensive income:									
Net income							348		348
Foreign currency translation adjustment, net of tax of $3								(7)	(7)
Reclassification adjustments for settled hedging positions, net of tax of $60								(110)	(110)
Reclassification adjustments for discontinued cash flow hedges, net of tax of $3								(7)	(7)
Changes in fair value of outstanding hedging positions, net of tax of ($41)								77	77
Total comprehensive income									301
Balance, December 31, 2005	129.4	1	(1.8)	(27)	1,186	(34)	1,296	(44)	2,378
Issuance of common and restricted stock,	1.7				41				41
					(34)	34			

Adoption of SFAS No. 123(R)									
Treasury stock			(0.1)	(3)					(3)
Stock-based compensation excess tax benefit					5				5
Minimum pension liability, net of tax of $1								(3)	(3)
Comprehensive income:									
Net income							591		591
Foreign currency translation adjustment, net of tax of ($10)								18	18
Reclassification adjustments for settled hedging positions, net of tax of $16								(29)	(29)
Changes in fair value of outstanding hedging positions, net of tax of ($35)								64	64
Total comprehensive income									644
Balance, December 31, 2006	131.1	1	(1.9)	(30)	1,198		1,887	6	3,062
Issuance of common and restricted stock	1.4				32				32
Stock-based compensation	0.7				34				34
Treasury stock, at cost				(2)					(2)
Stock-based compensation excess tax benefit					14				14
Comprehensive income:									
Net income							450		450
Foreign currency translation adjustment, net of tax of $7								(14)	(14)
Reclassification adjustments for settled hedging positions, net of tax of $2								(3)	(3)
Reclassification adjustments for discontinued cash flow hedges, net of tax of ($1)								2	2
Changes in fair value of outstanding hedging positions, net of tax of ($4)								6	6
Total comprehensive income									441

Balance, December 31, 2007	133.2	$	1	(1.9)	$	(32)	$	1,278	$		$	2,337	$	(3)	$ 3,581

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

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NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)

	Year Ended December 31, 2007	2006	2005
Cash flows from operating activities:			
Net income	$ 450	$ 591	$ 348
Adjustments to reconcile net income to net cash provided by operating activities:			
(Income) loss from discontinued operations, net of tax	(278)	19	(6)
Depreciation, depletion and amortization	682	624	520
Deferred taxes	30	316	134
Stock-based compensation	23	18	10
Early redemption cost on senior subordinated notes		8	
Impairment of floating production system and pipelines			(7)
Commodity derivative (income) expense			
Total (gains) losses	188	(389)	322
Realized gains (losses)	180	135	(112)
Ceiling test writedown		6	10
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(13)	10	(122)
Increase in inventories	(34)	(24)	(15)
(Increase) decrease in other current assets	27	(6)	(13)
(Increase) decrease in other assets	(8)	12	2
Increase (decrease) in accounts payable and accrued liabilities	(22)	17	48
Decrease in commodity derivative liabilities	(2)	(13)	(14)
Increase (decrease) in advances from joint owners	(46)	60	11
Increase (decrease) in other liabilities	(11)	8	3
Net cash provided by continuing activities	1,166	1,392	1,119
Net cash used in discontinued activities	(12)	(8)	(10)
Net cash provided by operating activities	1,154	1,384	1,109
Cash flows from investing activities:			
Additions to oil and gas properties	(1,930)	(1,567)	(1,026)
Acquisition of oil and gas properties	(658)		
Insurance recoveries		45	
Proceeds from sale of oil and gas properties	1,344	7	11
Proceeds from sale of floating production system and pipelines			7
Proceeds from sale of UK subsidiaries, net of cash on hand at sale date	491		
Additions to furniture, fixtures and equipment	(13)	(13)	(7)
Purchases of short-term investments	(271)	(714)	
Redemption of short-term investments	172	690	

Net cash used in continuing activities	(865)	(1,552)	(1,015)
Net cash used in discontinued activities	(41)	(110)	(21)
Net cash used in investing activities	(906)	(1,662)	(1,036)
Cash flows from financing activities:			
Proceeds from borrowings under credit arrangements	2,909	519	868
Repayments of borrowings under credit arrangements	(2,909)	(519)	(988)
Proceeds from issuance of senior subordinated notes		550	
Repayment of senior subordinated notes		(250)	
Repayment of senior notes	(125)		
Payments to discontinued operations	(38)	(143)	(36)
Proceeds from issuances of common stock	32	15	32
Stock-based compensation excess tax benefit	14	5	
Purchases of treasury stock		(3)	
Net cash provided by (used in) continuing activities	(117)	174	(124)
Net cash provided by discontinued activities	38	143	36
Net cash provided by (used in) financing activities	(79)	317	(88)
Effect of exchange rate changes on cash and cash equivalents	1	2	(4)
Increase (decrease) in cash and cash equivalents	170	41	(19)
Cash and cash equivalents from continuing operations, beginning of period	52	38	58
Cash and cash equivalents from discontinued operations, beginning of period	28	1	
Cash and cash equivalents, end of period	$ 250	$ 80	$ 39

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

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

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

In September 2007, we entered into an agreement to sell all of our interests in the U.K. North Sea for $511 million in cash. As a result of this agreement, the historical results of operations and financial position of our U.K. North Sea subsidiaries are reflected in our financial statements as discontinued operations. This reclassification affects not only the 2007 presentation of our financial statements, but also the presentation of all prior period financial statements. In October 2007, we closed and recorded a gain of $341 million. See Note 3, Discontinued Operations. Except where noted, discussions in these notes relate to our continuing operations only.

Dependence on Oil and Gas Prices

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

Use of Estimates

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

Reclassifications

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

Revenue Recognition

Substantially all of our natural gas and oil production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market sensitive prices. We record revenue when we deliver our production to the customer and collectibility is reasonably assured. Revenues from the production of oil and gas on

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

properties in which we have joint ownership are recorded under the sales method. Differences between these sales and our entitled share of production are not significant.

Foreign Currency

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

Cash and Cash Equivalents

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

Investments

Investments primarily consist of municipal and corporate bonds. These investments are classified as available-for-sale. Accordingly, unrealized gains and losses and the related deferred income tax effects are excluded from earnings and reported as a separate component of stockholders equity. Because of the short maturities of our investment securities, unrealized gains and losses are not material. Realized gains or losses are computed based on specific identification of the securities sold. We realized interest income and gains on our investment securities in 2007 and 2006 of $1 million and $5 million, respectively.

Allowance for Doubtful Accounts

We routinely assess the recoverability of all material trade and other receivables to determine their collectibility. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, our natural gas and crude oil receivables are collected within 45-60 days of production.

We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. As of December 31, 2007 and 2006, our allowance for doubtful accounts was immaterial.

Inventories

Inventories consist primarily of tubular goods and well equipment held for use in our oil and gas operations and oil produced in our operations offshore Malaysia and China but not sold. Inventories are carried at the lower of cost or market. Crude oil from our operations offshore Malaysia and China is produced into FPSOs and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 480,000 barrels and 176,000 barrels of crude oil valued at cost of $17 million and $5 million at December 31, 2007 and 2006, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depreciation, depletion and amortization expense.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis. We capitalized $71 million, $50 million and $43 million of internal

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

costs in 2007, 2006 and 2005, respectively. Interest expense related to unproved properties also is capitalized into oil and gas properties.

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

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using end of period oil and gas prices applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus
- the lower of cost or estimated fair value of properties not included in the costs being amortized, if any; less
- related income tax effects.

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

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

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil and gas prices decrease significantly or if we have substantial downward revisions in our estimated proved reserves. At December 31, 2007, the ceiling value of our reserves was calculated based upon quoted market prices of $6.80 per MMBtu for gas and $96.01 per barrel for oil, adjusted for market differentials. Using these prices, the ceiling value of our reserves exceeded our unamortized net capitalized costs of our domestic oil and gas properties by approximately $1.9 billion (net of tax). At December 31, 2007, the ceiling with respect to our oil and gas properties in Malaysia and China exceeded the net capitalized costs of the properties by approximately $117 million (net of tax) and $70 million (net of tax), respectively.

In September 2006, we decided to cease our exploration efforts in Brazil. As a result, we recognized a ceiling test writedown of $6 million for our Brazil cost center in the third quarter of 2006.

In December 2005, we decided to decrease our emphasis on exploration efforts in Brazil and to no longer pursue opportunities in several other countries. As a result, we recognized a ceiling test writedown of $10 million in the fourth quarter of 2005.

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

Furniture, Fixtures and Equipment

Furniture, fixtures and equipment are recorded at cost and are depreciated using the straight-line method over their estimated useful lives, which range from three to seven years. At December 31, 2007 and 2006, furniture, fixtures and equipment of $66 million and $52 million, respectively, are presented net of accumulated depreciation of $31 million and $24 million, respectively.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Goodwill

We assess the carrying amount of goodwill by testing the goodwill for impairment. The impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. We have deemed each country to be a goodwill reporting unit. The fair value of each reporting unit is determined and compared to the book value of that reporting unit. If the fair value of the reporting unit is less than its book value (including goodwill), then goodwill is reduced to its implied fair value and the amount of the writedown is charged to earnings. Goodwill is tested for impairment on an annual basis on December 31, or more frequently if an event occurs or circumstances change that have an adverse effect on the fair value of the reporting unit such that the fair value could be less than the book value of such unit.

The fair value of a reporting unit is based on our estimates of future net cash flows from proved reserves and from future exploration for and development of unproved reserves. Downward revisions of estimated reserves or production, increases in estimated future costs or decreases in oil and gas prices could lead to an impairment of all or a portion of goodwill in future periods.

We have not impaired any goodwill.

Accounting for Asset Retirement Obligations

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

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The change in our ARO for the three years ended December 31, 2007 is set forth below (in millions):

Balance at January 1, 2005	$ 216
Accretion expense	13
Additions	10
Revisions(1)	34
Settlements	(14)
Balance at December 31, 2005	259
Accretion expense	14
Additions	14
Revisions	(3)
Settlements	(19)
Balance at December 31, 2006	265
Accretion expense	9
Additions	15
Revisions	9
Settlements(2)	(236)
Balance at December 31, 2007	$ 62
Current portion of ARO	(6)
Total long-term ARO at December 31, 2007	$ 56

(1) Reflects an increase in the abandonment estimate of Gulf of Mexico platforms and facilities that were damaged or destroyed by Hurricanes Katrina and Rita.

(2) $215 million relates to the sale of our shallow water Gulf of Mexico assets. (See Note 4, Oil and Gas Assets)

Income Taxes

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

In July 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109. FIN 48 prescribes a comprehensive model for how companies should recognize, measure, present and disclose in their financial statements uncertain tax positions taken or expected to be taken on a tax return. Under FIN 48, tax positions are recognized in our consolidated financial statements as the largest amount of tax benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with tax authorities assuming full knowledge of the position and all relevant facts. These amounts are subsequently reevaluated and changes are recognized as adjustments to current period tax expense. FIN 48 also revised disclosure requirements to include an annual tabular rollforward of unrecognized tax benefits.

We adopted the provisions of FIN 48 on January 1, 2007. The adoption did not result in a material adjustment to our tax liability for unrecognized income tax benefits. During 2007 we recorded a $1 million FIN 48 liability.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

If applicable, we would recognize interest and penalties related to uncertain tax positions in interest expense. As of December 31, 2007, we had not accrued interest or penalties related to uncertain tax positions.

The tax years 2004-2007 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

Stock-Based Compensation

On January 1, 2006, we adopted FASB Statement (SFAS) No. 123 (revised 2004) (SFAS No. 123(R)), *Share-Based Payment,* to account for stock-based compensation. Among other things, SFAS No. 123(R) eliminated the use of Accounting Principles Board (APB) Opinion No. 25 (APB 25), Accounting for Stock Issued to Employees, and the intrinsic value method of accounting and required 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 and restricted share units. 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 10, Stock-Based Compensation, for a full discussion of our stock-based compensation.

Concentration of Credit Risk

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

The purchasers of our oil and gas production consist primarily of independent marketers, major oil and gas companies, refiners and gas pipeline companies. We perform credit evaluations of the purchasers of our production and monitor their financial condition on an ongoing basis. Based on our evaluations and monitoring, we obtain cash escrows, letters of credit or parental guarantees from some purchasers. Historically, we have sold a substantial portion of our oil and gas production to several purchasers (see *Major Customers* below). We have not experienced any significant losses from uncollectible accounts.

All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions involves the risk that the counterparties may be unable to meet the financial terms of the

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

transactions. The counterparties for all of our hedging transactions have an investment grade credit rating. We monitor on an ongoing basis the credit ratings of our hedging counterparties. At December 31, 2007, Barclays Capital, JPMorgan Chase Bank, Citibank, N.A., J Aron & Company, Bank of Montreal and Credit Suisse were the counterparties with respect to 84% of our future hedged production.

Major Customers

For the years ended December 31, 2007, 2006 and 2005, we sold oil and gas production that accounted for more than 10% of our consolidated revenues (before the effects of hedging) to Superior Natural Gas Corporation (15% in 2007, 18% in 2006 and 23% in 2005) and Louis Dreyfus Energy Services (less than 10% in 2007 and 2006 and 12% in 2005). 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.

Derivative Financial Instruments

We account for our derivative activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS Nos. 137, 138 and 149. The statement, as amended, establishes accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at its fair value. The statement requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Substantially all of the derivative instruments that we utilize are to manage the price risk attributable to our expected oil and gas production. We also have utilized derivatives to manage our exposure to variable interest rates (see Note 8, Debt *Interest Rate Swaps*).

Prior to the fourth quarter of 2005, we applied hedge accounting to qualifying derivatives we utilized to manage price risk associated with our oil and gas production. Accordingly, we recorded changes in the fair value of our swap, collar and floor contracts (other than contracts that are part of three-way collar contracts), including changes associated with time value, under the caption Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet. Gains or losses on these collar and floor contracts were reclassified out of Accumulated other comprehensive income (loss) Commodity derivatives and into oil and gas revenues when the forecasted sale of production occured. Any hedge ineffectiveness associated with contracts qualifying for and designated as cash flow hedges (which represented the amount by which the change in the fair value of the derivative differed from the change in the cash flows of the forecasted sale of production) was reported under the caption Commodity derivative income (expense) on our consolidated statement of income. The last of our previously designated cash flow hedges settled during 2007.

Beginning with the fourth quarter of 2005, we elected not to designate any future price risk management activities as accounting hedges under SFAS No. 133, and, accordingly, to account for them using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Derivative assets and Derivative liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of income under the caption Commodity derivative income (expense).

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

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Comprehensive Income (Loss)

Comprehensive income (loss) includes net earnings (loss) as well as unrealized gains and losses on derivative instruments, minimum pension liability and cumulative foreign currency translation adjustments, all recorded net of tax.

Insurance Recoveries

In August 2006, we reached an agreement with our insurance underwriters to settle all claims related to Hurricanes Katrina and Rita (business interruption, property damage and control of well/operator s extra expense) for $235 million. Based on the nature of the coverage provided under the policies, the settlement proceeds were recorded as follows:

- a cumulative inception to date credit of $58 million to other operating expense for amounts attributable to business interruption coverage;

- a credit of $48 million to our domestic full cost pool for amounts attributable to property damage coverage; and

- a cumulative credit of $129 million to lease operating expense for amounts attributable to all other hurricane repair and cleanup related coverage.

In our consolidated statement of cash flows, the cash related to the settlement of the property damage portion of our policies is reflected as a source of investing cash flows and the cash related to the settlement of our business interruption policy and our control of well/operator s extra expense policies is reflected as a source of operating cash flows.

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 granted a one-year deferral of the effective date of this statement 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 goodwill impairment). This statement 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 will adopt the provisions of this statement for all recurring measures of financial assets and liabilities on January 1, 2008. We have completed our initial evaluation of the impact of SFAS No. 157 as it relates to our financial assets and liabilities 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. An entity may not apply it before that date.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted average number of shares of common stock (other than unvested restricted stock and restricted stock units)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted shares and restricted stock units (using the treasury stock method). Under the treasury stock method the amount the employee must pay for exercising stock options, the amount of unrecognized compensation expense related to unvested stock-based compensation grants and the amount of excess tax benefits that would be recorded when the award becomes deductible are assumed to be used to repurchase shares. See Note 10, Stock-Based Compensation.

The following is the calculation of basic and diluted weighted average shares outstanding and EPS for each of the years in the three-year period ended December 31, 2007:

	2007	2006	2005
	(In millions, except per share data)		
Income (numerator):			
Income from continuing operations	$ 172	$ 610	$ 342
Income (loss) from discontinued operations, net of tax	278	(19)	6
Net income basic and diluted	$ 450	$ 591	$ 348
Weighted average shares (denominator):			
Weighted average shares basic	128	127	125
Dilution effect of stock options and unvested restricted stock outstanding at end of period	3	2	3
Weighted average shares diluted	131	129	128
Earnings per share:			
Basic			
Income from continuing operations	$ 1.35	$ 4.82	$ 2.73
Income (loss) from discontinued operations	2.17	(0.15)	0.05
Basic earnings per share	$ 3.52	$ 4.67	$ 2.78
Diluted			
Income from continuing operations	$ 1.32	$ 4.73	$ 2.68
Income (loss) from discontinued operations	2.12	(0.15)	0.05
Diluted earnings per share	$ 3.44	$ 4.58	$ 2.73

The calculation of shares outstanding for diluted EPS for the years ended December 31, 2007, 2006 and 2005 does not include the effect of 643 thousand, 912 thousand and 69 thousand outstanding stock options and unvested restricted shares or restricted share units, respectively, because to do so would be antidilutive.

3. Discontinued Operations:

In September 2007, we entered into an agreement to sell all of our interests in the U.K. North Sea for $511 million in cash. As a result of this agreement, the historical results of operations and financial position of our U.K. North Sea subsidiaries are reflected in our financial statements as discontinued operations. This reclassification affects not only the 2007 presentation of our financial statements, but also the presentation of all prior period financial statements. In October 2007, we closed the sale and recorded a gain of $341 million.

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31, 2007	2006	2005
	(In millions)		
Revenues	$ 8	$	$ 1
Operating expenses(1)	(62)	(7)	(3)
Loss from operations	(54)	(7)	(2)
Commodity derivative expense	(5)		
Gain on sale	341		
Other expense(2)	(4)		
Income (loss) before income taxes	278	(7)	(2)
Income tax provision (benefit)(3)		12	(8)
Income (loss) from discontinued operations, net of tax	$ 278	$ (19)	$ 6

(1) Operating expenses for the year ended December 31, 2007 include a ceiling test writedown of $47 million recorded in the first quarter of 2007.

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

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

The summarized financial position of the discontinued operations is as follows:

	December 31, 2006 (In millions)
Accounts receivable	$ 4
Other current assets	1
Total current assets	5
Oil and gas properties, net of accumulated depreciation, depletion and amortization	200

Total assets	$	205
Accrued liabilities	$	27
Asset retirement obligation		7
Total liabilities	$	34

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Oil and Gas Assets:

Oil and Gas Properties

Oil and gas properties consisted of the following at:

	December 31, 2007	2006	2005
	(In millions)		
Subject to amortization	$ 8,602	$ 7,719	$ 6,113
Not subject to amortization:			
Exploration in progress	250	182	145
Development in progress	30	49	16
Capitalized interest	103	94	71
Fee mineral interests	23	23	23
Other capital costs:			
Incurred in 2007	342		
Incurred in 2006	77	88	
Incurred in 2005	41	89	107
Incurred in 2004 and prior	323	445	519
Total not subject to amortization	1,189	970	881
Gross oil and gas properties	9,791	8,689	6,994
Accumulated depreciation, depletion and amortization	(3,868)	(3,234)	(2,630)
Net oil and gas properties	$ 5,923	$ 5,455	$ 4,364

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

We believe that our evaluation activities related to substantially all of the properties associated with costs not currently subject to amortization will be completed within four years except the Monument Butte field. Because of its size, evaluation of the field in its entirety will take significantly longer than four years. At December 31, 2007, 2006 and 2005, $264 million, $292 million and $316 million, respectively, of costs associated with the Monument Butte field were not subject to amortization.

Acquisition of Rocky Mountain Assets

In June 2007, we acquired Stone Energy Corporation s Rocky Mountain assets for $578 million in cash. These assets increased our existing presence and provided us with additional opportunities in many of the Rocky Mountain s most attractive areas. Our consolidated financial statements include the cash flows and

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

results of operations for these assets subsequent to June 30, 2007. This acquisition initially was financed through borrowings under our revolving credit agreement.

Pro Forma Results Rocky Mountain Asset Acquisition

The unaudited pro forma results presented below for the years ended December 31, 2007 and 2006 have been prepared to give effect to the Rocky Mountain asset acquisition described above on our results of operations as if it had been consummated on January 1, 2006. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if this acquisition had been completed on such date or to project our results of operations for any future period.

	Year Ended December 31, 2007	Year Ended December 31, 2006
	(Unaudited) (In millions, except per share data)	
Pro forma:		
Revenue	$ 1,831	$ 1,766
Income from operations	545	634
Net income	465	625
Basic earnings per share	$ 3.65	$ 4.93
Diluted earnings per share	$ 3.57	$ 4.84

Gulf of Mexico Asset Sale

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

Cherokee Basin Asset Sale

In September 2007, we sold our coal bed methane assets in the Cherokee Basin of northeastern Oklahoma for $128 million in cash. The cash flows and results of operations for these assets are included in our consolidated financial statements up to the date of sale.

Other Asset Acquisitions and Sales

During 2007, we acquired various other oil and gas properties for approximately $80 million and sold various other oil and gas properties for approximately $125 million.

All of the proceeds associated with our 2007 asset sales (other than the sale of our U.K. North Sea interests) were recorded as an adjustment to our domestic full cost pool.

5. Commodity Derivative Instruments:

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

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors requires the use of an option-pricing model.

All of our derivative contracts are carried at their fair value on our consolidated balance sheet under the captions Derivative assets and Derivative liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of income under the caption Commodity derivative income (expense). Settlements of derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2007, we had outstanding contracts with respect to our future production as set forth in the tables below.

Natural Gas

		NYMEX Contract Price per MMBtu					Estimated Fair Value Asset
			Collars				
		Swaps	Floors		Ceilings		
	Volume in	(Weighted		Weighted		Weighted	(Liability) (In
Period and Type of Contract	**MMMBtus**	**Average)**	**Range**	**Average**	**Range**	**Average**	**millions)**
January 2008 March 2008							
Price swap contracts	10,920	$ 8.74					$ 15
Collar contracts	22,595		$8.00	$ 8.00	$ 10.00 - $12.40	$ 11.04	18
April 2008 June 2008							
Price swap contracts	25,325	7.96					8
Collar contracts	5,715		7.00 - 8.00	7.64	9.00 - 9.70	9.34	3
July 2008 September 2008							
Price swap contracts	26,220	7.97					3
Collar contracts	5,760		7.00 - 8.00	7.64	9.00 - 9.70	9.34	2
October 2008 December 2008							
Price swap contracts	8,835	7.98					
Collar contracts	12,305		7.00 - 8.00	7.94	9.00 - 11.16	10.09	1
January 2009 December 2009							
Collar contracts	15,750		8.00	8.00	9.67 - 11.16	10.22	(4)
							$ 46

Oil

		NYMEX Contract Price per Bbl						Est
				Collars				V
		Additional Put		Floors		Ceilings		A
	Volume in		Weighted		Weighted		Weighted	(Li
and Type of Contract	**MBbls**	**Range**	**Average**	**Range**	**Average**	**Range**	**Average**	**mi**

y 2008 March 2008								
collar contracts	819	$ 25.00 - $29.00	$ 26.56	$ 32.00 - $35.00	$ 33.00	$ 49.50 - $52.90	$ 50.29	$
008 June 2008								
collar contracts	819	25.00 - 29.00	26.56	32.00 - 35.00	33.00	49.50 - 52.90	50.29	
08 September 2008								
collar contracts	828	25.00 - 29.00	26.56	32.00 - 35.00	33.00	49.50 - 52.90	50.29	
r 2008 December 2008								
collar contracts	828	25.00 - 29.00	26.56	32.00 - 35.00	33.00	49.50 - 52.90	50.29	
y 2009 December 2009								
collar contracts	3,285	25.00 - 30.00	27.00	32.00 - 36.00	33.33	50.00 - 54.55	50.62	
y 2010 December 2010								
collar contracts	3,645	25.00 - 32.00	28.60	32.00 - 38.00	34.90	50.00 - 53.50	51.52	
								$

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Basis Contracts

During 2007, we added several natural gas basis hedges to lock in the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points, as set forth in the table below.

	Onshore Gulf Coast		Rocky Mountains		Estimated Fair Value
	Volume in MMMBtus	Weighted Average Differential	Volume in MMMBtus	Weighted Average Differential	Asset (Liability) (In millions)
January 2008 March 2008			1,200	$ (1.62)	$ (1)
April 2008 June 2008			1,200	$ (1.62)	
July 2008 September 2008	4,270	$ (0.28)	1,200	$ (1.62)	2
October 2008 December 2008	6,440	$ (0.28)	1,200	$ (1.62)	4
January 2009 December 2009			5,520	$ (1.05)	1
January 2010 December 2010			5,520	$ (0.99)	2
January 2011 December 2011			5,280	$ (0.95)	1
January 2012 December 2012			4,920	$ (0.91)	1
					$ 10

Commodity Derivative Income (Expense)

The following table presents information about the components of commodity derivative income (expense) for each of the years in the three-year period ended December 31, 2007.

	Year Ended December 31,		
	2007	2006	2005
	(In millions)		
Cash flow hedges:			
Hedge ineffectiveness[1]	$	$ 5	$ (8)
Other derivative contracts:			
Realized loss on settlement of discontinued cash flow hedges[2]			(51)
Unrealized gain (loss) due to change in fair market value[3]	(365)	249	(202)
Realized gain (loss) on settlement	177	135	(61)
Total commodity derivative income (expense)	$ (188)	$ 389	$ (322)

(1) Hedge ineffectiveness is associated with our hedging contracts that qualified as cash flow hedges under SFAS No. 133.

(2) In the third quarter of 2005, as a result of the production deferrals experienced in the Gulf of Mexico related to Hurricanes Katrina and Rita, hedge accounting was discontinued on a portion of our contracts that had previously qualified as effective cash flow hedges of our Gulf of Mexico production and other contracts were redesignated as hedges of our onshore Gulf Coast production. As a result, realized losses of $51 million associated with derivative contracts for the third and fourth quarters of 2005, which were in excess of hedged physical deliveries for those periods, were reported as commodity derivative expense.

(3) The unrealized gain (loss) due to changes in fair market value is associated with our derivative contracts that are not designated for hedge accounting and represents changes in the fair value of these open contracts during the period.

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Accounts Receivable:

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

	December 31, 2007	December 31, 2006
	(In millions)	
Revenue	$ 142	$ 204
Joint interest	175	141
Other	15	29
Total accounts receivable	$ 332	$ 374

7. Accrued Liabilities:

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

	December 31, 2007	December 31, 2006
	(In millions)	
Revenue payable	$ 95	$ 95
Accrued capital costs	361	328
Accrued lease operating expenses	38	58
Employee incentive expense	80	63
Accrued interest on notes	19	21
Taxes payable	31	21
Other	47	55
Total accrued liabilities	$ 671	$ 641

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Debt:

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

	December 31, 2007	December 31, 2006
	(In millions)	
Senior unsecured debt:		
Revolving credit facility:		
Prime rate based loans	$	$
LIBOR based loans		
Total revolving credit facility		
Money market lines of credit[1]		
Total credit arrangements		
7.45% Senior Notes due 2007		125
Fair value of interest rate swaps		(1)
75/8% Senior Notes due 2011	175	175
Fair value of interest rate swaps[2]		(2)
Total senior unsecured notes	175	297
Total senior unsecured debt	175	297
65/8% Senior Subordinated Notes due 2014	325	325
65/8% Senior Subordinated Notes due 2016	550	550
Total debt	1,050	1,172
Less: Current portion of debt		124
Total long-term debt	$ 1,050	$ 1,048

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

(2) We have hedged $50 million principal amount of our $175 million 75/8% Senior Notes due 2011. The hedge provides for us to pay variable and receive fixed interest payments.

Credit Arrangements

In June 2007, we entered into a new revolving credit facility to replace our previous facility. The credit facility matures in June 2012 and provides for initial loan commitments of $1.25 billion from a syndicate of financial institutions, led by JPMorgan Chase as agent. The loan commitments may be increased to a maximum of $1.65 billion if the existing lenders increase their loan commitments or new financial institutions are added to the facility. Loans under the credit facility bear interest, at our option, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate substantially equal to the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (87.5 basis points per annum at December 31, 2007). At December 31, 2007 and 2006, we had no borrowings outstanding under the credit facility.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Under our new credit facility and our previous credit facilities, we pay or paid commitment fees on available but undrawn amounts based on a grid of our debt rating (0.175% per annum at December 31, 2007). We incurred fees under these arrangements of approximately $2 million for the years ended December 31, 2007, 2006 and 2005, respectively, which are recorded in interest expense on our consolidated statement of income.

The new credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0; maintenance of a ratio of total debt to earnings before gain or loss on the disposition of assets, interest expense, income taxes and noncash items (such as depreciation, depletion and amortization expense and unrealized gains and losses on commodity derivatives) of at least 3.5 to 1.0; and, so long as our debt rating is below investment grade, the maintenance of a ratio of the calculated net present value of our oil and gas properties to total debt of at least 1.75 to 1.00.

As of December 31, 2007, we had $15 million of undrawn letters of credit outstanding under our credit facility. Letters of credit issued under our credit facility are subject to an issuance fee of 12.5 basis points and annual fees based on a grid of our debt rating (87.5 basis points at December 31, 2007). We incurred fees of less than $1 million for each of the years ended December 31, 2007, 2006 and 2005, which are recorded in interest expense on our consolidated statement of income.

Subject to compliance with the restrictive covenants in our credit facility, we also have a total of $135 million of borrowing capacity under money market lines of credit with various financial institutions. At December 31, 2007, we had no borrowings outstanding under our money market lines.

Senior Notes

In October 2007, we repaid in full the $125 million principal amount of our 7.45% Senior Notes with cash on hand.

In February 2001, we issued $175 million aggregate principal amount of our 75/8% Senior Notes due 2011. The estimated fair value of these notes at December 31, 2007 and 2006 was $182 million and $183 million, respectively, based on quoted market prices on those dates.

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

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

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

Senior Subordinated Notes

In August 2004, we issued $325 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2014. The estimated fair value of these notes at December 31, 2007 and 2006 was $321 million and $323 million, respectively, based on quoted market prices on those dates.

In April 2006, we issued $550 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2016. The net proceeds from the offering (approximately $545 million) were used to redeem our

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

83/8% Senior Subordinated Notes due 2012 ($250 million aggregate principal amount and associated redemption premium) and for general corporate purposes, which included funding a portion of our 2006 capital program. The estimated fair value of these notes at December 31, 2007 and 2006 was $539 million and $546 million, respectively, based on quoted market prices on those dates.

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 the 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.

The indenture governing our senior subordinated notes may limit our ability 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.

Interest Rate Swaps

We have entered into interest rate swap agreements to take advantage of low interest rates and to obtain what we viewed as a more desirable proportion of variable and fixed rate debt. The agreements are designated as fair value hedges of a portion of our outstanding senior notes. Pursuant to SFAS No. 133, changes in the fair value of derivatives designated as fair value hedges are recognized as offsets to the changes in fair value of the exposure being hedged. As a result, the fair value of our interest rate swap agreements is reflected within our derivative assets or liabilities on our consolidated balance sheet and changes in their fair value are recorded as an adjustment to the carrying value of the associated long-term debt. Receipts and payments related to our interest rate swaps are reflected in interest expense.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Income Taxes:

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

	For the Year Ended December 31,		
	2007	2006	2005
	(In millions)		
U.S.	$ 269	$ 941	$ 515
Foreign	25	15	30
Total income before income taxes	$ 294	$ 956	$ 545

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

	For the Year Ended December 31,		
	2007	2006	2005
	(In millions)		
Current taxes:			
U.S. federal	$ 85	$ 31	$ 54
U.S. state	3	1	1
Foreign	4	(2)	14
Deferred taxes:			
U.S. federal	7	298	121
U.S. state	8	11	11
Foreign	15	7	2
Total provision for income taxes	$ 122	$ 346	$ 203

The provision for income taxes for each of the years in the three-year period ended December 31, 2007 was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	For the Year Ended December 31,		
	2007	2006	2005
	(In millions)		

Amount computed using the statutory rate	$ 103	$ 332	$ 190
Increase (decrease) in taxes resulting from:			
State and local income taxes, net of federal effect	7	8	8
Net effect of different tax rates in non-U.S. jurisdictions	10	(1)	1
Other	2	4	1
Valuation allowance		3	3
Total provision for income taxes	$ 122	$ 346	$ 203

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2007			December 31, 2006		
	U.S.	Foreign	Total	U.S.	Foreign	Total
			(In millions)			
Deferred tax asset:						
Net operating loss carryforwards	$ 130	$ 6	$ 136	$ 156	$ 6	$ 162
Alternative minimum tax credit	86		86	46		46
Commodity derivatives	110		110	55		55
Other, net	85		85	18		18
Valuation allowance		(6)	(6)		(6)	(6)
Deferred tax asset	411		411	275		275
Deferred tax liability:						
Commodity derivatives				(74)		(74)
Oil and gas properties	(1,457)	(23)	(1,480)	(1,219)	(8)	(1,227)
Deferred tax liability	(1,457)	(23)	(1,480)	(1,293)	(8)	(1,301)
Net deferred tax liability	(1,046)	(23)	(1,069)	(1,018)	(8)	(1,026)
Less net current deferred tax asset (liability)	35		35	(63)		(63)
Noncurrent deferred tax liability	$ (1,081)	$ (23)	$ (1,104)	$ (955)	$ (8)	$ (963)

As of December 31, 2007, we had net operating loss (NOL) carryforwards for federal and state income tax purposes of approximately $273 million and $906 million, respectively, that may be used in future years to offset taxable income. As of December 31, 2007, we had NOL carryforwards for international income tax purposes of approximately $17 million that may be used in future years to offset taxable income. We currently estimate that we will not be able to utilize these international NOLs, therefore a valuation allowance was established for them. Utilization of the NOL carryforwards is subject to annual limitations due to stock ownership changes. To the extent not utilized, the NOL carryforwards will begin to expire during the years 2019 through 2024. Utilization of NOL carryforwards is dependent upon generating sufficient taxable income in the appropriate jurisdictions within the carryforward period. Estimates of future taxable income can be significantly affected by changes in natural gas and oil prices, estimates of the timing and amount of future production and estimates of future operating and capital costs.

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

For Year Ended

	December 31, 2007	2006	2005
		(In millions)	
Balance at the beginning of the year	$ (6)	$ (3)	$
Charged to provision for income taxes:			
Brazil and other international NOL carryforwards		(3)	(3)
Balance at the end of the year	$ (6)	$ (6)	$ (3)

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

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Stock-Based Compensation:

On January 1, 2006, we adopted SFAS No. 123(R), *Share-Based Payment,* to account for stock-based compensation. Among other items, SFAS No. 123(R) eliminated the use of 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 and restricted share units. 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.

The modified prospective method requires us to estimate forfeitures in calculating the expense related to stock-based compensation as opposed to our prior policy of recognizing the forfeitures as they occurred. We recorded a cumulative effect gain on a change in accounting principle of $1 million as a result of the adoption of this standard. Because the amount was immaterial, we included it in general and administrative expense on our consolidated statement of income.

The modified prospective method precludes changes to the grant date fair value of equity awards granted before the required effective date of adoption of SFAS No. 123(R). Any unearned compensation recorded under APB 25 related to these awards is eliminated against the appropriate equity accounts. As a result, upon adoption we eliminated $34 million of unearned compensation cost and reduced by a like amount additional paid-in capital on our consolidated balance sheet.

Historically, we have used, and we anticipate continuing to use, unissued shares of stock when stock options are exercised. At December 31, 2007, we had approximately 2.6 million additional shares available for issuance pursuant to our existing employee and director plans. Of these shares, 1.5 million could be granted as restricted shares. Grants of restricted shares under our 2004 Omnibus Stock Plan reduce the total number of shares available under that plan by two times the number of restricted shares issued. Of the 1.5 million shares that can be granted as restricted shares, 0.4 million of such shares can be issued under our 2004 Omnibus Stock Plan.

For the year ended December 31, 2007, we recorded stock-based compensation expense of $34 million (pre-tax) for all plans. Of that amount, $10 million was capitalized in oil and gas properties. For the year ended December 31, 2007, we reported $14 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows. For the year ended December 31, 2006, we recorded stock-based compensation expense of $25 million (pre-tax) for all plans. Of that amount, $8 million was capitalized in oil and gas properties. For the year ended December 31, 2006, we reported $5 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

As of December 31, 2007, we had approximately $65 million of total unrecognized compensation expense related to unvested stock-based compensation awards. This compensation expense is expected to be recognized on a straight-line basis over the remaining vesting period of approximately 5 years.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table provides information about stock option activity for the years ended December 31, 2007 and 2006:

	Number of Shares Underlying Options (In millions)	Weighted Average Exercise Price per Share	Weighted Average Grant Date Fair Value per Share	Weighted Average Remaining Contractual Life (In years)	Aggregate Intrinsic Value [1] (In millions)
Outstanding at December 31, 2005	6.5	$ 23.60	$ 10.66	7.4	$ 171
Granted					
Exercised	(0.6)	20.91	9.31		(15)
Forfeited	(0.3)	27.50	12.54		(6)
Outstanding at December 31, 2006	5.6	23.68	10.71	6.3	124
Granted					
Exercised	(1.4)	20.94	9.43		41
Forfeited	(0.4)	29.45	13.37		8
Outstanding at December 31, 2007	3.8	$ 24.21	$ 10.95	5.6	$ 108
Exercisable at December 31, 2006	2.7	$ 19.58	$ 8.83	5.2	$ 71
Exercisable at December 31, 2007	2.3	$ 21.06	$ 9.45	4.8	$ 73

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

The following table summarizes information about stock options outstanding and exercisable at December 31, 2007:

Options Outstanding	Options Exercisable

Range of Exercise Prices	Number of Shares Underlying Options (In thousands)	Weighted Average Remaining Contractual Life (In years)	Weighted Average Exercise Price per Share	Number of Shares Underlying Options (In thousands)	Weighted Average Exercise Price per Share
$7.97 to $10.00	10	0.7	$ 7.97	10	$ 7.97
10.01 to 12.50					
12.51 to 15.00	289	2.0	14.64	289	14.64
15.01 to 17.50	810	4.6	16.64	713	16.64
17.51 to 22.50	551	4.3	18.99	498	18.94
22.51 to 27.50	690	6.2	24.75	336	24.71
27.51 to 35.00	1,227	7.0	31.16	405	31.03
35.01 to 41.72	220	7.4	38.00	54	38.02
	3,797	5.6	$ 24.21	2,305	$ 21.06

On December 31, 2007, the last reported sales price of our common stock on the the New York Stock Exchange was $52.70 per share.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Common stock issued upon the exercise of non-qualified stock options during 2005 resulted in a tax deduction for us equivalent to the compensation income recognized by the option holder and is recognized as a credit to additional paid in capital rather than as a reduction of income tax expense. For 2006 and 2007, only the excess tax benefit is recognized as a credit to additional paid in capital and is calculated as the amount by which the tax deduction we receive exceeds the deferred tax asset associated with recorded stock compensation expense. The amounts credited to additional paid in capital for 2007, 2006 and 2005 were approximately $14 million, $5 million and $17 million, respectively.

Restricted Shares. At December 31, 2007, our employees held 1.2 million restricted shares or restricted share units that primarily vest over the service period of four to five years. The vesting of these shares and units is dependant upon the employee s continued service with our company.

In addition, at December 31, 2007, our employees held 1.6 million restricted shares subject to performance-based vesting criteria (substantially all of which are considered market based restricted shares under SFAS No. 123(R)). In February 2007, 293,338 of these restricted performance-based shares were granted. The number of these shares that vest is based upon established performance targets that will be assessed on March 1, 2010. The grant date fair value of these shares was $24.04 per share for a total value of $7 million. The expense is being recognized ratably over the service period from February 2007 to March 2010. The grants to our executive officers provide that the shares will not be forfeited (but will still be subject to the performance-based vesting criteria) if the applicable executive retires after March 1, 2008 and stated age and continuous service requirements are met. To the extent that our executive officers qualify under this provision, the expense will be recognized ratably over the service period from February 2007 to the applicable retirement eligibility date. Substantially all of the remaining performance based shares may vest in whole or in part in 2008, 2009 or 2010. The percentage of the shares vesting, if any, in a year is subject to the achievement of the targets identified in the respective restricted share agreements.

Under our non-employee director restricted stock plan as in effect on December 31, 2007, immediately after each annual meeting of our stockholders, each of our non-employee directors then in office receive a number of restricted shares determined by dividing $100,000 by the fair market value of one share of our common stock on the date of the annual meeting. In addition, new non-employee directors elected other than at an annual meeting receive a number of restricted shares determined by dividing $100,000 by the fair market value of one share of our common stock on the date of their election. The forfeiture restrictions lapse on the day before the first annual meeting of stockholders following the date of issuance of the shares if the holder remains a director until that time. At December 31, 2007, 85,592 shares remained available for grants under the plan.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides information about restricted share and restricted share unit activity for the years ended December 31, 2007 and 2006:

	Service-Based Shares	Performance/ Market-Based Shares	Total Shares	Weighted Average Grant Date Fair Value per Share
	(In thousands, except per share data)			
Non-vested shares outstanding at December 31, 2005	710	640	1,350	$ 23.30
Granted	242	974	1,216	27.27
Forfeited	(67)	(96)	(163)	25.53
Vested	(218)	(2)	(220)	15.52
Non-vested shares outstanding at December 31, 2006	667	1,516	2,183	26.16
Granted	711	293	1,004	38.04
Forfeited	(120)	(111)	(231)	34.22
Vested	(97)	(84)	(181)	27.21
Non-vested shares outstanding at December 31, 2007	1,161	1,614	2,775	$ 29.77

The total fair value of restricted shares vested during the years ended December 31, 2007 and 2006 was $4.9 million and $3.4 million, respectively.

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

During 2007, options to purchase 56,429 shares of our common stock at a weighted average fair value of $11.70 per share were issued under the plan. The fair value of the options granted was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free weighted-average interest rate of 5.01%, an expected life of six months and weighted-average volatility of 34.31%. At December 31, 2007, 602,185 shares of our common stock remained available for issuance under the plan.

During 2006, options to purchase 51,445 shares of our common stock at a weighted average fair value of $13.35 per share were issued under the plan. The fair value of the options granted in 2006 was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free weighted-average interest rate of 4.83%, an expected life of six months and weighted-average volatility of 40.04%. At December 31, 2006, 658,614 shares of our common stock remained available for issuance under the plan.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pro forma Disclosures. Prior to January 1, 2006, we accounted for our employee stock-based compensation using the intrinsic value method prescribed by APB 25. As required by SFAS No. 123(R), we have disclosed below the effect on net income and earnings per share that would have been recorded had the fair value based method been used for 2005. The weighted average fair value of the options granted during 2005 was determined using the Black-Scholes option valuation method assuming no dividends, a weighted average risk-free interest rate of 3.76%, an expected life of 6.5 years and weighted average volatility of 38.13%.

	Year Ended December 31, 2005 (In millions, except per share data)
Net income:	
As reported[(1)]	$ 348
Pro forma[(2)]	339
Basic earnings per common share	
As reported	$ 2.78
Pro forma	2.70
Diluted earnings per common share	
As reported	$ 2.73
Pro forma	2.65

(1) Includes stock-based compensation costs, net of related tax effects, of $7 million.

(2) Includes stock-based compensation costs, net of related tax effects, of $16 million that would have been included in the determination of net income had the fair value based method been applied.

11. Pension Plan Obligation:

As a result of our acquisition of EEX in November 2002, we assumed responsibility for a defined benefit pension plan for current and former employees of EEX and its subsidiaries. The plan was amended, effective March 31, 2003, to cease all future retirement benefit accruals. Participant benefits were frozen as of that date and benefits will not increase based upon future service completed or compensation received. Accrued pension costs are funded based upon applicable requirements of federal law and deductibility for federal income tax purposes.

In September 2006, SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans was issued. SFAS No. 158 requires, among other things, the recognition of the funded status of each defined benefit pension plan, retiree health care and other post-retirement benefit plan and post-employment benefit plan on the balance sheet. Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. The initial impact of adoption of the standard due to unrecognized prior service costs or credits and net actuarial gains or losses as well as subsequent changes in the funded status is recognized as a component of accumulated comprehensive income in stockholders equity. Minimum pension liabilities and related intangible assets also are derecognized upon adoption. We adopted SFAS No. 158 as of December 31, 2006 and recorded a charge of

$2 million (net of tax of $1 million) to accumulated other comprehensive loss with a corresponding $3 million increase in accrued pension liability.

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables summarize changes in the benefit obligation, the plan assets and the funded status of our pension plan as well as the components of net periodic benefit costs, including key assumptions. The measurement dates for plan assets and obligations were December 31, 2007 and 2006.

	2007	2006
	(In millions)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ (34)	$ (30)
Interest cost	(2)	(2)
Benefits paid	1	1
Actuarial gain (loss)	1	(3)
Benefit obligation at end of year	$ (34)	$ (34)
Change in plan assets:		
Fair value of plan assets at beginning of year	$ 27	$ 23
Actual return on plan assets	2	3
Employer contributions	2	2
Benefits paid	(2)	(1)
Fair value of plan assets at end of year	$ 29	$ 27
Minimum liability recognition:		
Accumulated benefit obligation (ABO)	$ (34)	$ (34)
Fair value of plan assets	29	27
Unfunded ABO	(5)	(7)
Accrued pension liability (*before* minimum liability recognition)	2	4
Additional liability	$ (3)	$ (3)
Reconciliation of funded status:		
Projected benefit obligation (PBO)	$ (34)	$ (34)
Fair value of plan assets	29	27
Underfunded status	(5)	(7)
Unrecognized net loss	3	3
Accrued pension liability (*before* minimum liability recognition)	(2)	(4)
Transition adjustment required to recognize minimum liability:		
Accumulated other comprehensive loss	(3)	(3)

Accrued pension liability (*after* minimum liability recognition)	$ (5)	$ (7)
Check on reconciliation of accrued pension cost:		
Accrued pension liability at beginning of year	$ (7)	$ (7)
Company contributions	2	2
Change in accumulated other comprehensive loss		(2)
Accrued pension liability at end of year	$ (5)	$ (7)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2007	2006	2005
	(In millions)		
Net periodic benefit cost:			
Interest cost	$ 2	$ 2	$ 2
Expected return on plan assets	(2)	(2)	(2)
Total periodic benefit cost	$	$	$
Key Assumptions for Expense Purposes:			
Discount rate assumption	5.75%	5.75%	6.00%
Expected return on plan assets	8.00%	8.00%	8.00%
Key Assumptions for Disclosure Purposes:			
Discount rate assumption	6.46%	5.75%	5.75%
Expected return on plan assets	8.00%	8.00%	8.00%

In developing the overall expected long-term rate of return on assets, we used a building block approach in which rates of return in excess of inflation were considered separately for equity securities, debt securities and all other assets. The excess returns were weighted by the representative target allocation and added along with an approximate rate of inflation to develop the overall expected long-term rate of return.

Since our assumption of the plan, we have developed an investment policy to invest in a broad range of securities. The diversified portfolio aimed to maximize investment return without exposure to risk levels above those determined by us. In late 2007, we began the process to formally terminate the plan in 2008 or 2009. The current investment policy takes into consideration the retirement plan s benefit obligations, including the expected timing of benefit payments.

The following table sets forth the allocation of the plan s assets by category at December 31, 2007 and 2006 as well as the target allocation of assets for 2008.

	Target Allocation 2008	Percentage of Plan Assets at December 31, 2007	2006
Plan Asset Categories:			
Cash and money market funds			
Equity securities			44%
Debt securities	100%	100%	56%
Total	100%	100%	100%

The estimated future benefit payments under the plan for the next ten years are as follows (in millions):

Year ending December 31,	
2008	$ 1
2009	1
2010	1
2011	1
2012	2
2013 2017	11

During 2008, we anticipate making a contribution of approximately $4 million to the plan.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Employee Benefit Plans:

Post-Retirement Medical Plan

We sponsor a post-retirement medical plan that covers all retired employees until they reach age 65. At December 31, 2007, our accumulated benefit obligation was $6 million and our accrued benefit cost was $4 million. Our net periodic benefit cost has been approximately $1 million per year.

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

2008 2012	$ 1
2013 2017	4

Incentive Compensation Plan

Our 2003 incentive compensation plan provides for the creation each calendar year of an award pool that is generally equal to 5% of our adjusted net income (as defined in the plan) plus the revenues attributable to an overriding royalty interest bearing on the interests of investors that participate in certain of our activities. Adjusted net income for purposes of this plan excludes unrealized gains and losses on commodity derivatives. The plan is administered by the Compensation & Management Development Committee of our Board of Directors and award amounts are recommended by our chief executive officer. All employees are eligible for awards if employed on both October 1 and December 31 of the performance period. Awards under the plan may, and generally do, have both a current and a deferred component. Deferred awards are paid in four annual installments, each installment consisting of 25% of the deferred award, plus interest. Total expense under the plan for the years ended December 31, 2007, 2006 and 2005 was $51 million, $38 million and $42 million, respectively.

401(k) and Deferred Compensation Plans

We sponsor a 401(k) profit sharing plan under Section 401(k) of the Internal Revenue Code. This plan covers all of our employees other than employees of our foreign subsidiaries. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee s salary, subject to limitations imposed by the Internal Revenue Service. We also sponsor a highly compensated employee deferred compensation plan. This non-qualified plan allows an eligible employee to defer a portion of his or her salary or bonus on an annual basis. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee s salary, subject to limitations imposed by the plan. Our contribution with respect to each participant in the deferred compensation plan is reduced by the amount of contribution made by us to our 401(k) plan for that participant. Our combined contributions to these two plans totaled $4 million per year for the years ended December 31, 2007 and 2006 and $3 million for the year ended 2005.

13. Commitments and Contingencies:

Lease Commitments

We have various commitments under non-cancellable operating lease agreements for office space, equipment and drilling rigs. The majority of these commitments are related to multi-year contracts for drilling

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

rigs that are accounted for as capital additions to our oil and gas properties. Future minimum payments required under these leases as of December 31, 2007 are as follows (in millions):

Year Ending December 31,	
2008	$ 122
2009	83
2010	6
2011	6
Thereafter	24
Total minimum lease payments	$ 241

Rent expense with respect to our lease commitments for office space for the years ended December 31, 2007, 2006 and 2005 was $6 million, $4 million and $5 million, respectively.

Other Commitments

As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work related commitments for, among other things, drilling wells, obtaining and processing seismic data and fulfilling other cash commitments. At December 31, 2007, these work related commitments totaled $7 million and were comprised of $3 million in the United States and $4 million internationally.

Litigation

In December 2002, a lawsuit against our Mid-Continent subsidiary was filed in Beaver County, Oklahoma and was later certified as a class action royalty owner lawsuit. The complaint alleged that we improperly reduced royalty payments for certain expenses and charges, and also claimed breach of contract and breach of fiduciary duties, among other claims. In April 2007, we entered into a settlement agreement that has since received court approval. In the first quarter of 2007, we increased our litigation settlement reserve for the lawsuit, which resulted in a charge to earnings that was recorded under the caption General and administrative on our consolidated income statement.

We also have been named as a defendant in a number of other lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

14. Stockholder Rights Plan:

In 1999, we adopted a stockholder rights plan. The plan is designed to ensure that all of our stockholders receive fair and equal treatment if a takeover of our company is proposed. It includes safeguards against partial or two-tiered tender offers, squeeze-out mergers and other abusive takeover tactics.

The plan provides for the issuance of one right for each outstanding share of our common stock. The rights will become exercisable only if a person or group acquires 20% or more of our outstanding voting stock or announces a tender or exchange offer that would result in ownership of 20% or more of our voting stock.

Each right will entitle the holder to buy one one-thousandth (1/1000) of a share of a new series of junior participating preferred stock at an exercise price of $85 per right, subject to antidilution adjustments. Each one one-thousandth of a share of this new preferred stock has the dividend and voting rights of, and is designed to be substantially equivalent to, one share of our common stock. Our Board of Directors may, at its option, redeem all rights for $0.01 per right at any time prior to the acquisition of 20% or more of our outstanding voting stock by a person or group.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

If a person or group acquires 20% or more of our outstanding voting stock, each right will entitle holders, other than the acquiring party or parties, to purchase shares of our common stock having a market value of $170 for a purchase price of $85, subject to antidilution adjustments.

The plan also includes an exchange option. If a person or group acquires 20% or more, but less than 50%, of our outstanding voting stock, our Board of Directors may, at its option, exchange the rights in whole or part for shares of our common stock. Under this option, we would issue one share of our common stock, or one one-thousandth of a share of new preferred stock, for each two shares of our common stock for which a right is then exercisable. This exchange would not apply to rights held by the person or group holding 20% or more of our voting stock.

If, after the rights have become exercisable, we merge or otherwise combine with another entity, or sell assets constituting more than 50% of our assets or producing more than 50% of our earnings power or cash flow, each right then outstanding will entitle its holder to purchase for $85, subject to antidilution adjustments, a number of the acquiring party s common shares having a market value of twice that amount.

The plan will not prevent, nor is it intended to prevent, a takeover of our company. Since the rights may be redeemed by our Board of Directors under certain circumstances, they should not interfere with any merger or other business combination approved by our Board. The rights do not in any way diminish our financial strength, affect reported earnings per share or interfere with our business plans.

15. Segment Information:

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

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables provide the geographic operating segment information required by SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information,* as well as results of operations of oil and gas producing activities required by SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*, for the years ended December 31, 2007, 2006 and 2005 for our continuing operations. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

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

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Malaysia	China (In millions)	Other International	Total
Year Ended December 31, 2006:					
Oil and gas revenues	$ 1,611	$ 49	$ 13	$	$ 1,673
Operating expenses:					
Lease operating	261	14	1		276
Production and other taxes	49	11	1		61
Depreciation, depletion and amortization	611	9	4		624
Ceiling test writedown				6	6
General and administrative	116	1	1		118
Other	(11)				(11)
Allocated income taxes	211	5	2		
Net income (loss) from oil and gas properties	$ 374	$ 9	$ 4	$ (6)	
Total operating expenses					1,074
Income from operations					599
Interest expense, net of interest income, capitalized interest and other					(32)
Commodity derivative income					389
Income from continuing operations before income taxes					$ 956
Total long-lived assets	$ 5,208	$ 182	$ 65	$	$ 5,455
Additions to long-lived assets	$ 1,621	$ 109	$ 24	$ 1	$ 1,755

	United States	Malaysia	China (In millions)	Other International	Total
Year Ended December 31, 2005:					
Oil and gas revenues	$ 1,690	$ 72	$	$	$ 1,762
Operating expenses:					
Lease operating	190	15			205
Production and other taxes	58	6			64
Depreciation, depletion and amortization	510	10			520

Ceiling test writedown				10	10
General and administrative	101	1			102
Other	(29)				(29)
Allocated income taxes	301	15		(1)	
Net income (loss) from oil and gas properties	$ 559	$ 25	$	$ (9)	
Total operating expenses					872
Income from operations					890
Interest expense, net of interest income, capitalized interest and other					(23)
Commodity derivative expense					(322)
Income from continuing operations before income taxes					$ 545
Total long-lived assets	$ 4,226	$ 87	$ 45	$ 6	$ 4,364
Additions to long-lived assets	$ 1,076	$ 41	$ 8	$ 3	$ 1,128

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Supplemental Cash Flow Information:

	Year Ended December 31, 2007	2006	2005
	(In millions)		
Cash payments:			
Interest payments, net of interest capitalized of $47, $44 and $46 during 2007, 2006 and 2005, respectively	$ 56	$ 39	$ 25
Income tax payments	87	11	54
Non-cash items excluded from the statement of cash flows:			
Accrued capital expenditures	$ (24)	$ (124)	$ (66)
Asset retirement costs	194	(8)	(44)

17. Related Party Transaction:

David A. Trice, our Chairman, President and Chief Executive Officer, and Susan G. Riggs, our Treasurer, are minority owners of Huffco International L.L.C. In May 1997, prior to Mr. Trice and Ms. Riggs joining us, we acquired from Huffco an entity now known as Newfield China, LDC, the owner of a 12% interest in a three field unit located on Blocks 04/36 and 05/36 in Bohai Bay, offshore China. Huffco retained preferred shares of Newfield China that provide for an aggregate dividend equal to 10% of the excess of proceeds received by Newfield China from the sale of oil, gas and other minerals over all costs incurred with respect to exploration and production in Block 05/36, plus the cash purchase price we paid Huffco for Newfield China ($6 million). At December 31, 2007, Newfield China had approximately $31 million of unrecovered exploration and production costs. As a result, no dividends have been paid to date on its preferred shares. Newfield anticipates that it will begin paying preferred dividends in the second quarter of 2009. Based on our estimate of the net present value of the proved reserves associated with Block 05/36, the indirect interests (through Huffco) in Newfield China s preferred shares held by Mr. Trice and Ms. Riggs had a net present value of approximately $256,000 and $99,000, respectively, at December 31, 2007.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. Quarterly Results of Operations (Unaudited):

The results of operations by quarter for the years ended December 31, 2007 and 2006 are as follows:

	2007 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil and gas revenues	$ 440	$ 526	$ 419	$ 398
Income from operations[1]	93	183	131	124
Income (loss) from continuing operations	(47)	152	92	(25)
Income (loss) from discontinued operations, net of tax[2]	(49)	(2)	(9)	338
Net income (loss)	(96)	150	83	313
Basic earnings (loss) per common share[3]:				
Income (loss) from continuing operations	$ (0.37)	$ 1.19	$ 0.72	$ (0.20)
Income (loss) from discontinued operations	(0.38)	(0.02)	(0.07)	2.63
Basic earnings (loss) per common share	$ (0.75)	$ 1.17	$ 0.65	$ 2.43
Diluted earnings (loss) per common share[3]:				
Income (loss) from continuing operations	$ (0.37)	$ 1.17	$ 0.70	$ (0.19)
Income (loss) from discontinued operations	(0.38)	(0.02)	(0.06)	2.57
Diluted earnings (loss) per common share	$ (0.75)	$ 1.15	$ 0.64	$ 2.38

	2006 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil and gas revenues	$ 430	$ 391	$ 425	$ 427
Income from operations[4]	233	112	185	69
Income from continuing operations	149	94	267	100
Loss from discontinued operations, net of tax			(1)	(18)
Net income	149	94	266	82
Basic earnings (loss) per common share[3]:				
Income from continuing operations	$ 1.18	$ 0.74	$ 2.11	$ 0.79
Loss from discontinued operations			(0.01)	(0.14)
Basic earnings per common share	$ 1.18	$ 0.74	$ 2.10	$ 0.65
Diluted earnings (loss) per common share[3]:				

Income from continuing operations	$ 1.17	$ 0.73	$ 2.07	$ 0.77
Loss from discontinued operations			(0.01)	(0.13)
Diluted earnings per common share	$ 1.17	$ 0.73	$ 2.06	$ 0.64

(1) Income from operations for the first quarter of 2007 includes $36 million of hurricane related expenses incurred subsequent to the settlement of all of our insurance claims related to the 2005 storms.

(2) Income (loss) from discontinued operations, net of tax, for the first quarter of 2007 includes a full cost ceiling test writedown of $47 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income (loss) from discontinued operations, net of tax, for the fourth quarter of 2007 includes a $341 million gain on the sale of our interests in the U.K. North Sea.

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

(4) Income from operations for the second quarter of 2006 includes an early redemption premium of $19 million paid with respect to our 83/8% Senior Subordinated Notes due 2012 when they were redeemed in May 2006 and the write-off of the remaining unamortized original issuance cost of these notes of $8 million.

Income from operations in the third quarter of 2006 includes a $34 million credit to lease operating expense resulting from the difference between the proceeds received in the third quarter of 2006 from the settlement of all of our insurance claims related to Hurricanes Katrina and Rita and our actual hurricane related expenses incurred to date.

Income from operations in the fourth quarter of 2006 includes $50 million of repair expenses incurred subsequent to the settlement of all of our insurance claims related to Hurricanes Katrina and Rita.

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SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED

Costs incurred for oil and gas property acquisitions, exploration and development for each of the years in the three-year period ended December 31, 2007 are as follows:

	United States	Malaysia	China	Other International	Total	Discontinued Operations United Kingdom[5]
	(In millions)					
2007:						
Property acquisitions[1]:						
Unproved	$ 258	$	$ 2	$	$ 260	$
Proved	479				479	
Exploration[2]	1,320	47	11	1	1,379	2
Development[3]	353	169	11		533	24
Total costs incurred[4]	$ 2,410	$ 216	$ 24	$ 1	$ 2,651	$ 26
2006:						
Property acquisitions:						
Unproved	$ 62	$ 8	$	$	$ 70	$ 3
Proved	8	7			15	
Exploration[2]	1,174	48	2	1	1,225	27
Development[3]	377	46	22		445	121
Total costs incurred[4]	$ 1,621	$ 109	$ 24	$ 1	$ 1,755	$ 151
2005:						
Property acquisitions:						
Unproved	$ 56	$ 15	$ 1	$ 1	$ 73	$ 3
Proved	26				26	
Exploration[2]	713	23	2	2	740	27
Development[3]	281	3	5		289	5
Total costs incurred[4]	$ 1,076	$ 41	$ 8	$ 3	$ 1,128	$ 35

(1) Includes $578 million related to the Stone Energy Rocky Mountain asset acquisition.

(2) Includes $240 million, $363 million and $277 million of United States costs for non-exploitation activities for 2007, 2006 and 2005, respectively; $23 million, $22 million and $17 million of Malaysia costs for non-exploitation activities for 2007, 2006 and 2005, respectively; $11 million, $1 million and $1 million of

China costs for non-exploitation activities for 2007, 2006 and 2005, respectively; and $1 million, $1 million and $2 million of Other International costs for non-exploitation activities for 2007, 2006 and 2005, respectively.

(3) Includes $21 million, $11 million and $44 million for 2007, 2006 and 2005, respectively, of asset retirement costs recorded in accordance with SFAS No. 143.

(4) Totals for each year have not been adjusted to reflect the impact of the following:

	2007	2006	2005
		(In millions)	
Proceeds from property sales domestic	$ 1,295	$ 23	$ 10
Asset retirement costs associated with property sales	216		
Insurance settlement proceeds domestic	1	48	
Ceiling test writedown international		6	10
	$ 1,512	$ 77	$ 20

(5) Exploration cost includes $7 million and $26 million for non-exploitation activities for 2006 and 2005, respectively. Total costs incurred includes $3 million and $5 million for 2007 and 2006, respectively, of asset retirement costs recorded in accordance with SFAS No. 143.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Capitalized costs for our oil and gas producing activities consisted of the following at the end of each of the years in the three-year period ended December 31, 2007:

	United States	Malaysia	China	Other International	Total	Discontinued Operations United Kingdom
			(In millions)			
December 31, 2007:						
Proved properties	$ 8,240	$ 310	$ 82	$	$ 8,632	$
Unproved properties	1,031	116	10	2	1,159	
	9,271	426	92	2	9,791	
Accumulated depreciation, depletion and amortization	(3,791)	(61)	(16)		(3,868)	
Net capitalized costs	$ 5,480	$ 365	$ 76	$ 2	$ 5,923	$
December 31, 2006:						
Proved properties	$ 7,555	$ 146	$ 67	$	$ 7,768	$ 170
Unproved properties	856	63	2		921	32
	8,411	209	69		8,689	202
Accumulated depreciation, depletion and amortization	(3,203)	(27)	(4)		(3,234)	(2)
Net capitalized costs	$ 5,208	$ 182	$ 65	$	$ 5,455	$ 200
December 31, 2005:						
Proved properties	$ 6,017	$ 67	$ 45	$	$ 6,129	$ 30
Unproved properties	822	37		6	865	18
	6,839	104	45	6	6,994	48
Accumulated depreciation, depletion and amortization	(2,613)	(17)			(2,630)	(2)
Net capitalized costs	$ 4,226	$ 87	$ 45	$ 6	$ 4,364	$ 46

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

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

Estimated Net Quantities of Proved Oil and Gas Reserves

The following table sets forth our total net proved reserves and our total net proved developed reserves as of December 31, 2004, 2005, 2006 and 2007 and the changes in our total net proved reserves during the three-year period ended December 31, 2007, as estimated by our petroleum engineering staff:

	Oil, Condensate and Natural Gas Liquids (MMBbls)				Natural Gas (Bcf)	Total Bcfe				
									Discontinued Operations	
	U.S.	Malaysia(3)	China(3)	Total	U.S.	U.S.	Malaysia	China	United Kingdom	Total
Proved developed and undeveloped reserves as of:										
December 31, 2004	84.8	5.7		90.5	1,239.6	1,748.1	34.3		1.5	1,783.9
Revisions of previous estimates	0.8	(0.1)		0.7	10.7	15.6	(0.8)			14.8
Extensions, discoveries and other additions	9.2	4.7	5.3	19.2	249.3	304.5	28.0	31.5	69.2	433.2
Purchases of properties	0.3			0.3	16.9	18.9				18.9
Sales of properties	(0.2)			(0.2)	(6.1)	(7.1)			(1.2)	(8.3)
Production	(8.4)	(1.3)		(9.7)	(183.2)	(233.8)	(7.7)		(0.1)	(241.6)
December 31, 2005	86.5	9.0	5.3	100.8	1,327.2	1,846.2	53.8	31.5	69.4	2,000.9
Revisions of previous estimates	2.2	(0.7)	0.3	1.8	(70.0)	(57.0)	(4.0)	2.1	(16.8)	(75.7)
Extensions, discoveries and other additions	11.9	8.1		20.0	466.2	537.6	48.8		15.4	601.8

Purchases of properties					1.3	1.3				1.3
Sales of properties					(0.1)	(0.2)			(12.7)	(12.9)
Production	(7.8)	(0.9)	(0.3)	(9.0)	(189.6)	(236.1)	(5.6)	(1.7)		(243.4)
December 31, 2006	92.8	15.5	5.3	113.6	1,535.0	2,091.8	93.0	31.9	55.3	2,272.0
Revisions of previous estimates	0.4	(0.2)	0.9	1.1	(18.3)	(16.2)	(1.0)	5.3		(11.9)
Extensions, discoveries and other additions	12.6	0.3		12.9	583.3	658.7	1.6			660.3
Purchases of properties(1)	9.6			9.6	162.9	220.6				220.6
Sales of properties(2)	(12.4)			(12.4)	(267.7)	(342.2)			(53.6)	(395.8)
Production	(7.8)	(1.8)	(0.8)	(10.4)	(185.2)	(231.8)	(10.6)	(4.8)	(1.7)	(248.9)
December 31, 2007	95.2	13.8	5.4	114.4	1,810.0	2,380.9	83.0	32.4		2,496.3
Proved developed reserves as of:										
December 31, 2004	49.7	5.7		55.4	1,003.9	1,302.2	34.3		1.4	1,337.9
December 31, 2005	54.6	4.3		58.9	1,010.2	1,338.0	25.8			1,363.8
December 31, 2006	60.9	2.4	1.8	65.1	1,093.6	1,458.9	14.6	10.6		1,484.1
December 31, 2007	61.3	6.3	3.9	71.5	1,136.4	1,504.7	37.5	23.4		1,565.6

(1) Substantially all of the purchases of U.S. oil and gas reserves relates to our June 2007 acquisition of Stone Energy s Rocky Mountain assets.

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

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

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NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

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

The following information was developed utilizing procedures prescribed by SFAS No. 69, Disclosures about Oil and Gas Producing Activities. The information is based on estimates prepared by our petroleum engineering staff. The standardized measure of discounted future net cash flows should not be viewed as representative of the current value of our proved oil and gas reserves. It and the other information contained in the following tables may be useful for certain comparative purposes, but should not be solely relied upon in evaluating us or our performance.

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

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

Under the standardized measure, future cash inflows were estimated by applying year-end oil and gas prices applicable to our reserves to the estimated future production of year-end proved reserves. Future cash inflows do not reflect the impact of open hedge positions (see Note 5, Commodity Derivative Instruments). Future cash inflows were reduced by estimated future development, abandonment and production costs based on year-end costs in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying year-end statutory tax rates to aggregate future pre-tax net cash flows reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% discount rate and year-end prices and costs are required by SFAS No. 69.

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

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NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

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

	U.S.	Malaysia	China	Discontinued Operations United Kingdom	Total
			(In millions)		
2007:					
Future cash inflows	$ 18,539	$ 1,364	$ 408	$	$ 20,311
Less related future:					
Production costs	(4,107)	(732)	(115)		(4,954)
Development and abandonment costs	(2,124)	(58)	(21)		(2,203)
Future net cash flows before income taxes	12,308	574	272		13,154
Future income tax expense	(3,854)	(95)	(55)		(4,004)
Future net cash flows before 10% discount	8,454	479	217		9,150
10% annual discount for estimating timing of cash flows	(4,421)	(111)	(87)		(4,619)
Standardized measure of discounted future net cash flows	$ 4,033	$ 368	$ 130	$	$ 4,531
2006:					
Future cash inflows	$ 12,922	$ 930	$ 247	$ 276	$ 14,375
Less related future:					
Production costs	(3,033)	(476)	(97)	(46)	(3,652)
Development and abandonment costs	(1,667)	(132)	(9)	(54)	(1,862)
Future net cash flows before income taxes	8,222	322	141	176	8,861
Future income tax expense	(2,309)	(121)	(51)	(97)	(2,578)
Future net cash flows before 10% discount	5,913	201	90	79	6,283
10% annual discount for estimating timing of cash flows	(2,727)	(66)	(28)	(15)	(2,836)
Standardized measure of discounted future net cash flows	$ 3,186	$ 135	$ 62	$ 64	$ 3,447

2005:					
Future cash inflows	$ 15,458	$ 568	$ 268	$ 658	$ 16,952
Less related future:					
Production costs	(2,688)	(334)	(55)	(65)	(3,142)
Development and abandonment costs	(1,192)	(47)	(27)	(146)	(1,412)
Future net cash flows before income taxes	11,578	187	186	447	12,398
Future income tax expense	(3,585)	(88)	(54)	(232)	(3,959)
Future net cash flows before 10% discount	7,993	99	132	215	8,439
10% annual discount for estimating timing of cash flows	(3,259)	(19)	(51)	(57)	(3,386)
Standardized measure of discounted future net cash flows	$ 4,734	$ 80	$ 81	$ 158	$ 5,053

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NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Set forth in the table below is a summary of the changes in the standardized measure of discounted future net cash flows for our proved oil and gas reserves during each of the years in the three-year period ended December 31, 2007:

	U.S.	Malaysia	China	Discontinued Operations United Kingdom	Total
			(In millions)		
2007:					
Beginning of the period	$ 3,186	$ 135	$ 62	$ 64	$ 3,447
Revisions of previous estimates:					
Changes in prices and costs	1,125	173	70		1,368
Changes in quantities	(62)	(6)	29		(39)
Changes in future development costs	(37)	(22)			(59)
Development costs incurred during the period	258	112		22	392
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	1,341	16			1,357
Purchases and sales of reserves in place, net	(438)			(153)	(591)
Accretion of discount	434	22	9		465
Sales of oil and gas, net of production costs	(1,082)	(52)	(22)	(7)	(1,163)
Net change in income taxes	(614)	15	(1)	71	(529)
Production timing and other	(78)	(25)	(17)	3	(117)
Net increase (decrease)	847	233	68	(64)	1,084
End of the period	$ 4,033	$ 368	$ 130	$	$ 4,531
2006:					
Beginning of the period	$ 4,734	$ 80	$ 81	$ 158	$ 5,053
Revisions of previous estimates:					
Changes in prices and costs	(1,959)	(24)	(41)	(231)	(2,255)
Changes in quantities	(123)	(13)	7	(53)	(182)
Changes in future development costs	(196)			(14)	(210)
Development costs incurred during the period	326	33	19	110	488
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	958	88		38	1,084
Purchases and sales of reserves in place, net	2			(60)	(58)
Accretion of discount	679	16	11	32	738
Sales of oil and gas, net of production costs	(1,656)	(25)	(12)		(1,693)
Net change in income taxes	899	(12)	(2)	96	981

Production timing and other	(478)	(8)	(1)	(12)	(499)
Net increase (decrease)	(1,548)	55	(19)	(94)	(1,606)
End of the period	$ 3,186	$ 135	$ 62	$ 64	$ 3,447
2005:					
Beginning of the period	$ 3,557	$ 44	$	$ 1	$ 3,602
Revisions of previous estimates:					
Changes in prices and costs	1,729	25			1,754
Changes in quantities	(186)	(1)			(187)
Changes in future development costs	(91)				(91)
Development costs incurred during the period	180	(2)			178
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	1,103	81	111	324	1,619
Purchases and sales of reserves in place, net	18			(1)	17
Accretion of discount	356	5			361
Sales of oil and gas, net of production costs	(1,160)	(25)			(1,185)
Net change in income taxes	(738)	(49)	(30)	(166)	(983)
Production timing and other	(34)	2			(32)
Net increase	1,177	36	81	157	1,451
End of the period	$ 4,734	$ 80	$ 81	$ 158	$ 5,053

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

None.

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

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2007 in ensuring that material information was accumulated and communicated to management, and made known to our Chief Executive Officer and Chief Financial Officer, on a timely basis to allow disclosure as required in this report.

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

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

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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

None.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

The information required by Item 10 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2008 annual meeting of stockholders to be held on May 1, 2008 and to the information set forth in Item 4A of this report.

Corporate Code of Business Conduct and Ethics

We have adopted a corporate code of business conduct and ethics for directors, officers (including our principal executive officer, principal financial officer and controller or principal accounting officer) and employees. Our corporate code includes a financial code of ethics applicable to our chief executive officer, chief financial officer and controller or chief accounting officer. Both of these codes are available on our website at *www.newfield.com.* Stockholders may request a free copy of these codes from:

Newfield Exploration Company
Attention: Investor Relations
363 North Sam Houston Parkway East, Suite 2020
Houston, Texas 77060
(281) 405-4284

Corporate Governance Guidelines

We have adopted corporate governance guidelines, which are available on our website. Stockholders may request a free copy of our corporate governance guidelines from the address and phone number set forth above under Corporate Code of Business Conduct and Ethics.

Committee Charters

The charters of the Audit Committee, the Compensation & Management Development Committee and the Nominating & Corporate Governance Committee of our Board of Directors are available on our website. Stockholders may request a free copy of any of these charters from the address and phone number set forth above under Corporate Code of Business Conduct and Ethics.

Section 16(a) Beneficial Ownership Reporting Compliance

Information regarding Section 16(a) beneficial ownership reporting compliance is incorporated herein by reference to such information as set forth in the proxy statement for our 2008 annual meeting of stockholders to be held on May 1, 2008.

Certifications

The New York Stock Exchange requires the chief executive officer of each listed company to certify annually that he or she is not aware of any violation by the company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. Our chief executive officer provided such certification to the NYSE in 2007. In addition, the certifications of our chief executive officer and chief financial officer required by Section 302 of the Sarbanes-Oxley Act have been filed as exhibits to this report and to our annual report on Form 10-K for the year ended December 31, 2007.

Item 11. ***Executive Compensation***

The information required by Item 11 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2008 annual meeting.

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

The information required by Item 12 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2008 annual meeting of stockholders to be held on May 1, 2008.

Item 13. ***Certain Relationships and Related Transactions***

The information required by Item 13 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2008 annual meeting of stockholders to be held on May 1, 2008.

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

The information required by Item 14 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2008 annual meeting of stockholders to be held on May 1, 2008.

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PART IV

Item 15. *Exhibits and Financial Statement Schedules*

Financial Statements

Reference is made to the index set forth on page 50 of this report.

Financial Statement Schedules

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

Exhibits

Exhibit Number	Title
3.1	Second Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield s Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, setting forth the terms of the Series A Junior Participating Preferred Stock, par value $0.01 per share (incorporated by reference to Exhibit 3.5 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-12534))
3.2	Restated Bylaws of Newfield (as amended by Amendment No. 1 thereto adopted January 31, 2000 and Amendment No. 2 thereto adopted July 28, 2005) (incorporated by reference to Exhibit 3.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 1-12534))
4.1	Rights Agreement, dated as of February 12, 1999, between Newfield and ChaseMellon Shareholder Services L.L.C., as Rights Agent, specifying the terms of the Rights to Purchase Series A Junior Participating Preferred Stock, par value $0.01 per share, of Newfield (incorporated by reference to Exhibit 1 to Newfield s Registration Statement on Form 8-A filed with the SEC on February 18, 1999 (File No. 1-12534))
4.3	Senior Indenture dated as of February 28, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 28, 2001 (File No. 1-12534))
4.4	Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.5 of Newfield s Registration Statement on Form S-3 (Registration No. 333-71348))

4.4.1	Second Supplemental Indenture, dated as of August 18, 2004, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.6.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-122157))
4.4.2	Third Supplemental Indenture, dated as of April 3, 2006, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4.3 of Newfield s Current Report on Form 8-K filed with the SEC on April 3, 2006 (File No. 1-12534))
10.1	Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1 to Newfield s Registration Statement on Form S-8 (Registration No. 33-92182))

Exhibit Number	Title
10.1.1	First Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.1.2	Second Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.2	Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1.1 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.1	Amendment of 1998 Omnibus Stock Plan, dated May 7, 1998 (incorporated by reference to Exhibit 4.1.2 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.2	Second Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (as amended on May 7, 1998) (incorporated by reference to Exhibit 10.2 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.2.3	Third Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 99.2 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.3	Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.7.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
10.3.1	First Amendment to Newfield Exploration Company 2000 Omnibus Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.3 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.3.2	Second Amendment to Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 99.3 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.4	Newfield Exploration Company 2004 Omnibus Stock Plan (As Amended and Restated Effective February 7, 2007) (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K/A filed with the SEC on March 1, 2007 (File No. 1-12534))
* 10.4.1	First Amendment to Newfield Exploration Company 2004 Omnibus Stock Plan (As Amended and Restated Effective February 7, 2007)
10.5	Newfield Exploration Company 2007 Omnibus Stock Plan (incorporated by reference to Appendix A to Newfield s definitive proxy statement on Schedule 14A for its 2007 Annual Meeting of Stockholders filed with the SEC on March 16, 2007 (File No. 1-12534))
* 10.5.1	First Amendment to Newfield Exploration Company 2007 Omnibus Stock Plan
10.6	Form of TSR 2003 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf and Mark J. Spicer dated as of February 12, 2003 (incorporated by reference to Exhibit 10.3.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.7	Form of TSR 2005 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 8, 2005 (incorporated by reference to Exhibit 10.1 to Newfield s Current

	Report on Form 8-K filed with the SEC on February 11, 2005 (File No. 1-12534))
10.8	Form of TSR 2006 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 14, 2006 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))

Exhibit Number	Title
10.9	Form of TSR 2007 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Michael Van Horn, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, John H. Jasek, Gary D. Packer and James T. Zernell dated as of February 14, 2007 (incorporated by reference to Exhibit 10.2 to Newfield s Current Report on Form 8-K filed with the SEC on February 21, 2007 (File No. 1-12534))
10.10	Form of 2007 Restricted Unit Agreement between Newfield and each of David A. Trice, David F. Schaible, Michael Van Horn, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, John H. Jasek, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Brian L. Rickmers and Susan G. Riggs dated as of February 14, 2007 (incorporated by reference to Exhibit 10.3 to Newfield s Current Report on Form 8-K filed with the SEC on February 21, 2007 (File No. 1-12534))
10.11	Form of Restricted Stock Agreement between Newfield and (a) John Marziotti dated as of August 1, 2007 and (b) Lee K. Boothby dated as of October 1, 2007 (incorporated by reference to Exhibit 10.10 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
10.12	Form of 2008 Restricted Unit Agreement between Newfield and each of David A. Trice, Lee K. Boothby, Michael Van Horn, Terry W. Rathert, William D. Schneider, George T. Dunn, Gary D. Packer, John H. Jasek, James T. Zernell, William Mark Blumenshine, Mona Leigh Bernhardt, Stephen C. Campbell, James J. Metcalf, John D. Marziotti, Brian L. Rickmers, Susan G. Riggs and Mark J. Spicer dated as of February 7, 2008 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 14, 2008 (File No. 1-12534))
10.13	Form of 2008 Stock Option Agreement between Newfield and David A. Trice dated as of February 7, 2008 (incorporated by reference to Exhibit 10.2 to Newfield s Current Report on Form 8-K filed with the SEC on February 14, 2008 (File No. 1-12534))
10.14	Form of 2008 Stock Option Agreement between Newfield and each of Lee K. Boothby, Michael Van Horn, George T. Dunn, Gary D. Packer, John H. Jasek, James T. Zernell, William Mark Blumenshine, Mona Leigh Bernhardt, Stephen C. Campbell, James J. Metcalf, John D. Marziotti, Brian L. Rickmers, Susan G. Riggs and Mark J. Spicer dated as of February 7, 2008 (incorporated by reference to Exhibit 10.3 to Newfield s Current Report on Form 8-K filed with the SEC on February 14, 2008 (File No. 1-12534))
10.15	Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10.18 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
10.15.1	First Amendment to Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10.5.1 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 1-12534))
10.16	Second Amended and Restated Newfield Exploration Company 2003 Incentive Compensation Plan (incorporated by reference to Exhibit 10.2 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
10.17	Newfield Exploration Company Deferred Compensation Plan as Amended and Restated as of July 26, 2007 (incorporated by reference to Exhibit 10.3 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
10.18	Second Amended and Restated Newfield Exploration Company Change of Control Severance Plan (incorporated by reference to Exhibit 10.4 to Newfield s Quarterly Report on Form 10-Q for the

	quarterly period ended June 30, 2007 (File No. 1-12534))
10.19.1	Form of Second Amended and Restated Change of Control Severance Agreement between Newfield and each of David A. Trice, David F. Schaible and Terry W. Rathert dated effective as of July 26, 2007 (incorporated by reference to Exhibit 10.5 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))

Exhibit Number	Title
10.19.2	Form of Second Amended and Restated Change of Control Severance Agreement between Newfield and each of George T. Dunn, Gary D. Packer and William D. Schneider dated effective as of July 26, 2007 (incorporated by reference to Exhibit 10.8 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
10.19.3	Amended and Restated Change of Control Severance Agreement between Newfield and Michael Van Horn dated effective as of July 26, 2007 (incorporated by reference to Exhibit 10.6 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
10.19.4	Second Amended and Restated Change of Control Severance Agreement between Newfield and Lee K. Boothby dated effective as of July 26, 2007 (incorporated by reference to Exhibit 10.7 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
10.19.5	Form of Amended and Restated Change of Control Severance Agreement between Newfield and each of John H. Jasek and James T. Zernell dated effective as of July 26, 2007 (incorporated by reference to Exhibit 10.9 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
10.20	Form of Indemnification Agreement between Newfield and each of its directors and executive officers (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005 (File No. 1-12534))
10.21	Resolution of Members Establishing the Preferences, Limitations and Relative Rights of Series A Preferred Shares of Huffco China, LDC dated May 14, 1997 (incorporated by reference to Exhibit 10.15 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))
10.22	Credit Agreement, dated as of June 22, 2007, among Newfield Exploration Company, the Lenders party thereto, and JP Morgan Chase Bank, N.A., as Administrative Agent and as Issuing Bank (incorporated by reference to Exhibit 10.11 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 (File No. 1-12534))
*21.1	List of Significant Subsidiaries
*23.1	Consent of PricewaterhouseCoopers LLP
*31.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed or furnished herewith.

Identifies management contracts and compensatory plans or arrangements.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 29th day of February, 2008.

NEWFIELD EXPLORATION COMPANY

By: /s/ DAVID A. TRICE

David A. Trice

Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated and on the 29th day of February, 2008.

Signature	Title
/s/ DAVID A. TRICE David A. Trice	Chairman, President and Chief Executive Officer and Director (Principal Executive Officer)
/s/ TERRY W. RATHERT Terry W. Rathert	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ BRIAN L. RICKMERS Brian L. Rickmers	Controller (Principal Accounting Officer)
/s/ PHILIP J. BURGUIERES Philip J. Burguieres	Director
/s/ PAMELA J. GARDNER Pamela J. Gardner	Director
/s/ DENNIS HENDRIX Dennis Hendrix	Director

/s/ JOHN R. KEMP III	Director
John R. Kemp III	
/s/ J. MICHAEL LACEY	Director
J. Michael Lacey	
/s/ JOSEPH H. NETHERLAND	Director
Joseph H. Netherland	
/s/ HOWARD H. NEWMAN	Director
Howard H. Newman	

Signature	Title
/s/ THOMAS G. RICKS	Director
Thomas G. Ricks	
/s/ JUANITA F. ROMANS	Director
Juanita F. Romans	
/s/ C. E. SHULTZ	Director
C. E. Shultz	
/s/ J. TERRY STRANGE	Director
J. Terry Strange	

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EXHIBIT INDEX

Exhibit Number	Title
3.1	Second Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield s Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, setting forth the terms of the Series A Junior Participating Preferred Stock, par value $0.01 per share (incorporated by reference to Exhibit 3.5 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-12534))
3.2	Restated Bylaws of Newfield (as amended by Amendment No. 1 thereto adopted January 31, 2000 and Amendment No. 2 thereto adopted July 28, 2005) (incorporated by reference to Exhibit 3.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 1-12534))
4.1	Rights Agreement, dated as of February 12, 1999, between Newfield and ChaseMellon Shareholder Services L.L.C., as Rights Agent, specifying the terms of the Rights to Purchase Series A Junior Participating Preferred Stock, par value $0.01 per share, of Newfield (incorporated by reference to Exhibit 1 to Newfield s Registration Statement on Form 8-A filed with the SEC on February 18, 1999 (File No. 1-12534))
4.3	Senior Indenture dated as of February 28, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 28, 2001 (File No. 1-12534))
4.4	Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.5 of Newfield s Registration Statement on Form S-3 (Registration No. 333-71348))
4.4.1	Second Supplemental Indenture, dated as of August 18, 2004, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.6.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-122157))
4.4.2	Third Supplemental Indenture, dated as of April 3, 2006, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4.3 of Newfield s Current Report on Form 8-K filed with the SEC on April 3, 2006 (File No. 1-12534))
10.1	Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1 to Newfield s Registration Statement on Form S-8 (Registration No. 33-92182))
10.1.1	First Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.1.2	Second Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 to Newfield s Current Report on Form 8-K filed with the SEC on May 5,

	2005 (File No. 1-12534))
10.2	Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1.1 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.1	Amendment of 1998 Omnibus Stock Plan, dated May 7, 1998 (incorporated by reference to Exhibit 4.1.2 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.2	Second Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (as amended on May 7, 1998) (incorporated by reference to Exhibit 10.2 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))

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	Exhibit Number	Title
	10.2.3	Third Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 99.2 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
	10.3	Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.7.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
	10.3.1	First Amendment to Newfield Exploration Company 2000 Omnibus Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.3 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
	10.3.2	Second Amendment to Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 99.3 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
	10.4	Newfield Exploration Company 2004 Omnibus Stock Plan (as Amended and Restated Effective February 7, 2007) (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K/A filed with the SEC on March 1, 2007 (File No. 1-12534))
*	10.4.1	First Amendment to Newfield Exploration Company 2004 Omnibus Stock Plan (as Amended and Restated Effective February 7, 2007)
	10.5	Newfield Exploration Company 2007 Omnibus Stock Plan (incorporated by reference to Appendix A to Newfield s definitive proxy statement on Schedule 14A for its 2007 Annual Meeting of Stockholders filed with the SEC on March 16, 2007 (File No. 1-12534))
*	10.5.1	First Amendment to Newfield Exploration Company 2007 Omnibus Stock Plan
	10.6	Form of TSR 2003 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf and Mark J. Spicer dated as of February 12, 2003 (incorporated by reference to Exhibit 10.3.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
	10.7	Form of TSR 2005 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 8, 2005 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 11, 2005 (File No. 1-12534))
	10.8	Form of TSR 2006 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 14, 2006 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
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