NEWFIELD EXPLORATION CO /DE/
Form 10-K/A
January 15, 2008

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

Form 10-K/A
(Amendment No. 1)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2006

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 or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer 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, 2006 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 26, 2007, there were 129,995,347 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 3, 2007, which is incorporated by reference into Part III of this Form 10-K.

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EXPLANATORY NOTE

We are filing this amendment to our annual report for the year ended December 31, 2006 to reflect the changes made in response to the comments received by us from the Staff of the Securities and Exchange Commission in connection with the Staff s review of the report. Our consolidated financial position and consolidated results of operations for the periods presented have not been restated from the consolidated financial position and consolidated results of operations originally reported. For convenience and ease of reference, we are filing the annual report in its entirety with the applicable changes. Unless otherwise stated, all information contained in this amended report is as of March 1, 2007, the original filing date of our annual report for the year ended December 31, 2006.

Pursuant to the Rules of the SEC, currently dated certifications from our Chief Executive Officer and Chief Financial Officer as required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are filed herewith.

The changes made to the report include a revision to the Drilling Activity table on page 12 and the costs incurred for oil and gas property acquisitions, exploration and development listed in the table in our Supplementary Oil and Gas Disclosures Unaudited on page 91. The changes reflect recategorization of development wells and activities that were previously categorized as exploratory wells and activities.

The following table reflects the changes made to the Drilling Activities table on page 12. Positive numbers indicate the number of wells added to a category and negative numbers indicate the number of wells removed from a category.

	2006		2005		2004	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory wells:						
China:						
Productive	(14)	(1.7)				
Nonproductive						
United Kingdom:						
Productive	(1)	(0.9)				
Nonproductive						
Total	(15)	(2.6)				
Development wells:						
China:						
Productive	14	1.7				
Nonproductive						
United Kingdom:						
Productive	1	0.9				
Nonproductive						
Total	15	2.6				

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The following table reflects the changes made to the table in our Supplementary Oil and Gas Disclosures Unaudited on page 91. Positive numbers indicate amounts added to a category and negative numbers indicate amounts removed from a category.

	United States	United Kingdom	Malaysia	China	Other International	Total
2006:						
Property acquisitions:						
Unproved	$	$	$	$	$	$
Proved						
Exploration	(210)	(64)		(14)		(288)
Development	210	64		14		288
Total costs incurred	$	$	$	$	$	$
2005:						
Property acquisitions:						
Unproved	$	$	$	$	$	$
Proved						
Exploration	(92)					(92)
Development	92					92
Total costs incurred	$	$	$	$	$	$
2004:						
Property acquisitions:						
Unproved	$	$	$	$	$	$
Proved						
Exploration	(63)					(63)
Development	63					63
Total costs incurred	$	$	$	$	$	$

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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 crude oil and natural gas properties. Our company was founded in 1989 and for the first ten years of our existence we focused on the shallow waters of the Gulf of Mexico. Today, we have a diversified asset base. Our domestic areas of operation include the Anadarko and Arkoma Basins of the Mid-Continent, the onshore Gulf Coast, the Uinta Basin of the Rocky Mountains and the Gulf of Mexico. Internationally, we are active offshore Malaysia and China and in the U.K. North Sea.

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.

At year-end 2006, we had proved reserves of 2.3 Tcfe. Of those reserves:

- 70% were natural gas;
- 65% were proved developed;
- 35% were located in the Mid-Continent;
- 20% were located onshore in the Gulf Coast;
- 20% were located in the Rocky Mountains;
- 15% were located in the Gulf of Mexico; and
- 10% were located internationally.

Strategy

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

- growing reserves through the drilling of a balanced risk/reward portfolio and select acquisitions;
- focusing on select geographic areas;
- controlling operations and costs;

using advanced technologies; and

attracting and retaining a quality workforce through equity ownership and other performance-based incentives.

Drilling Program. In an effort to manage the risks associated with our strategy to grow reserves through the drill bit, each year we drill a greater number of lower risk, low to moderate potential wells and a lesser number of higher risk, higher potential prospects. Our low-risk drilling opportunities in the Mid-Continent, the Rocky Mountains and the shallow waters of Malaysia and the Gulf of Mexico are complemented with higher potential plays in areas like the Gulf of Mexico s deepwater and in international waters. We actively look for new drilling ideas on our existing property base and on properties that may be acquired. In 2006, substantially all of our reserve additions came through the drillbit.

Acquisitions. 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. From 2000 through 2004, we made several large acquisitions that helped establish new focus areas. Since 2004, our production and reserve growth has come primarily through the success of our drilling programs. Recently, higher commodity prices and stiff competition for acquisitions have significantly increased the cost of available properties. As a result, we have looked to alternative ways to gain access to oil and gas properties such as joint venture alliances and leasing efforts. We did not complete any significant acquisitions during 2006.

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. We also believe that geographic focus allows us to make the most efficient use of our 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 2006, we operated about 70% of our net total production.

Technology. By investing in technology, we give our people the tools they need to succeed. We rely on 3-D seismic surveys in all of our major areas of operation and use the full range of technologies to identify opportunities.

Equity Ownership and Incentive Compensation. We want our employees to act like owners. To achieve this, 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 26, 2007, our employees owned or had options to acquire 7.3% of our outstanding common stock on a fully diluted basis.

Focus Areas

Mid-Continent. Through an acquisition in January 2001, we added the Mid-Continent as a focus area. Since that time, we have tripled our proved reserves and tripled our production from this area. The Mid-Continent now represents 35% of our total proved reserves. The Mid-Continent is a gas-rich province characterized by multiple productive zones. Our two most active plays, the Woodford Shale and the Mountain Front Wash, are characterized by multiple producing horizons and large acreage positions. We drilled 354 wells in the Mid-Continent in 2006 and have a multi-year inventory of lower risk drilling opportunities. Our Mid-Continent division is managed by our Tulsa, Oklahoma office.

Onshore Gulf Coast. We established onshore Gulf Coast operations in 1995 and made major acquisitions in 2000 and 2002 to establish a significant presence in the onshore Gulf Coast. Today, this region is a major focus area for us, representing about 20% of our total proved reserves. Our operations are concentrated in South Texas, the Val Verde Basin of West Texas and East Texas.

Rocky Mountains. Through an acquisition in August 2004, we entered the Uinta Basin of the Rocky Mountains. The Monument Butte Field, located in northeastern Utah, now accounts for approximately 20% of our total proved reserves. The field offers a multi-year drilling inventory of lower risk wells. We drilled 199 wells in the field in 2006. The multiple basins of the Rocky Mountains, which have significant remaining reserves, offer us opportunities for growth and we are actively pursuing acquisition opportunities in those basins. Our Rocky Mountain division is managed by our Denver, Colorado office.

Gulf of Mexico. We are active in all of the major plays in the Gulf of Mexico: the traditional shelf, the deep and ultra-deep shelf and deepwater. Although traditional shelf plays are mature, we remain active and are finding creative ways to leverage our geologic expertise and infrastructure. We operate about 180 production platforms in shallow water. This infrastructure facilitates cost effective operations and timely development of our discoveries. We have added significant new projects in deepwater over the last two years. At year-end 2006, we were producing from four deepwater fields, and our first operated development the Wrigley Field is being prepared for production.

Although we believe that significant opportunities remain in the deep shelf play, the economics of these prospects have been negatively impacted by significantly higher rates for offshore rigs. As a result, we have elected to defer most of these opportunities.

In 2005 and 2006, we drilled our first ultra-deep well on our Blackbeard prospect. This well was part of an exploration initiative we refer to as Treasure Project. The well was drilled to a total depth of 30,067 feet and encountered a thin gas-bearing sand below 30,000 feet. The well failed to reach its primary targets because of higher than expected pressure. The well has been temporarily abandoned. We are working with the MMS to extend the leases containing the prospect, all of which are beyond their primary terms. The ultra-deep targets are high risk but the potential reserve impact could be significant. We have more than 90 lease blocks associated with this concept. There is no production from these depths on the Gulf of Mexico shelf today.

International. Our international operations have grown significantly over the last several years. We now have production from offshore China and Malaysia and are preparing to bring the Grove Field, our first operated field in the U.K. North Sea, on-line. We continue to seek ways to grow our presence in these areas and have a team dedicated to finding new international regions where we can employ our expertise. We have international offices in Beijing, Kuala Lumpur and London.

We have interests in two offshore Malaysia blocks that together include current production, undeveloped discoveries and lower risk drilling prospects in shallow water and a large deepwater exploration concession. We have four fields under development and we drilled our first deepwater prospect in late 2006. The well, located on Block 2C, found non-commercial quantities of natural gas. The geologic information gathered from this well is being incorporated into our interpretation for other prospects on Block 2C. We have a commitment to drill one additional exploratory well on this block.

During the third quarter of 2006, we commenced production from two oil fields in China s Bohai Bay. During 2005, we added two license areas offshore Hong Kong in the Pearl River Mouth Basin and we acquired seismic data for these areas in 2006. We are seeking additional opportunities both onshore and offshore China.

For revenues from our domestic and international operations, see Note 16, Segment Information, to our consolidated financial statements appearing later in this report.

Plans for 2007

Our capital budget for 2007 is approximately $1.8 billion, including about $50 million for continuing hurricane repairs in the Gulf of Mexico and excluding approximately $100 million of capitalized interest and overhead. About $290 million has been earmarked for exploration (exclusive of exploitation) activities. We do not budget for potential acquisitions. We plan to drill approximately 450 wells in 2007, about 80% of which are lower risk wells in the Mid-Continent or the Uinta Basin.

Mid-Continent. Our largest focus area investment in 2007 will be the Mid-Continent. We expect to drill about 200 wells and invest approximately $700 million. The majority of the planned drilling is associated with the development of our Woodford Shale play. We expect to drill about 150 horizontal wells in the play in 2007.

Onshore Gulf Coast. In 2007, we will balance development drilling of lower risk opportunities with some higher risk, higher impact exploration tests. South Texas will be a significant part of this focus area in 2007. We plan to drill 10-12 wells in South Texas under a joint venture agreement with Exxon-Mobil. Overall, we plan to drill about 70 wells and invest approximately $350 million in the onshore Gulf Coast during 2007.

Rocky Mountains. Our primary capital program in the Monument Butte Field consists of drilling shallow, lower risk wells and water injection wells, waterflood optimization activities and investment in field infrastructure. We plan to drill about 150 wells in the field during 2007. A successful 20-acre infill drilling pilot program, conducted in 2006, indicates that field development will support an additional 1,000 wells.

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Production from Monument Butte has been negatively impacted by refining capacity in the Salt Lake City area. We expect our 2007 oil sales to benefit from recent agreements with refiners which allow for firm capacity of approximately 11,000 BOPD (gross) through 2008 and 7,400 BOPD (gross) through 2009. We are working with other area refiners to secure additional capacity. Please see the discussion under the caption *We may not achieve future production growth from our Monument Butte Field* in Item 1A of this report. Our 2007 capital budget includes $135 million for our activities in the Rocky Mountains.

Gulf of Mexico. We expect to drill about 20-25 wells in 2007, including 15-20 in the traditional shelf and 4-5 in deepwater. About $440 million of our capital budget for 2007 has been allocated to our Gulf of Mexico program. Our activities in the traditional shelf are helping to maintain production levels while generating significant cash flow to fund other growth areas.

International. In recent years, we have invested increasing amounts in international operations. Recent field developments offshore Malaysia and China and in the U.K. North Sea are expected to add significant production in 2007. Our planned investment in international ventures for 2007 is expected to be more than $200 million.

In 2007, our activities in Malaysia will focus on bringing our Abu Field on-line. In addition, development continues at the Puteri Field on PM 318 and the East Belumut and Chermingat Fields on PM 323. Offshore China, our drilling program for the Bohai Bay will focus on development of our two commercial fields, where production commenced in the middle of 2006. In the U.K. North Sea, our Grove Field is being prepared for production. We plan to drill three exploration prospects in the North Sea in 2007. Under an agreement signed in 2006, a significant portion of the costs associated with these exploration prospects will be funded by another company. The first of the three wells has been drilled and was unsuccessful.

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 of this production are readily available.

Competition

Competition in the oil and gas industry is intense, particularly access to drilling rigs and other services, the acquisition of properties and the hiring and retention of technical personnel. For a further discussion, please see the information set forth under the caption *Competitive industry conditions may negatively affect our ability to conduct operations* in Item 1A of this report.

Employees

As of February 15, 2007, we had 871 employees. All but 70 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.

Our future success depends on our ability to find, develop and acquire oil and gas reserves. Most of our producing properties have declining production rates. To maintain production levels, we must locate and develop or acquire new oil and gas reserves to replace those depleted by production. Without successful exploration or acquisition activities, our reserves, production and revenues will decline rapidly. We may be unable to find and develop or acquire additional reserves at an acceptable cost. In addition, substantial capital is required to replace and grow reserves. If lower oil and gas prices or operating constraints or production difficulties result in our cash flow from operations being less than expected or limit our ability to borrow under our credit arrangements, we may be unable to expend the capital necessary to locate and develop or acquire new oil and gas reserves.

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 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 certain economic assumptions, some of which are mandated by the SEC, 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 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 estimated 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 December 31. Actual future prices and costs may be materially higher or lower than the prices and costs we used.

If oil and gas prices decrease, we may be required to take writedowns. We may be required to writedown the carrying value 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 exploration 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 carrying value of our properties quarterly, based on prices in effect (including the effect of our hedging contracts that are designated for hedge accounting) as of the end of each quarter or as of the time of reporting our results. The carrying value 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.

We may not achieve production growth from our Monument Butte Field. In August 2004, we acquired the 100,000-acre Monument Butte Field located in the Uinta Basin of Northeast Utah for approximately $575 million. 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. Currently, area refineries have limited capacity to refine this type of crude oil. As a result we curtailed some production from the field in 2006. In early 2007, we reached agreements with two refiners that secure base load capacity of approximately 11,000 BOPD of capacity through 2008 and 7,400 BOPD through 2009. We are working with other area refiners to secure additional capacity. Without additional refining capacity, our ability to increase production from the field will be limited. In addition, the price we receive for our production from the field has been adversely affected by the increased availability of black wax and other competitive crude oil in the market.

Waterflooding, a secondary recovery operation that involves the injection of large volumes of water into an oil-producing reservoir, is necessary to recover the oil reserves in the Monument Butte Field. In 2006, we signed a water source agreement with the Duchesne Conservancy Water District that secures access to approximately 62,000 barrels of water per day through May 2051. This agreement provides sufficient water for our current operations and will permit some future growth but our ability to significantly increase production from the field may be limited if we do not obtain additional sources of water in the future.

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.

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We may be unable to obtain the drilling rigs or support services necessary for our 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 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 experiencing increased costs.

The oil and gas exploration and production industry is very competitive, and some of our exploration and production competitors have greater financial and other resources than we do. The oil and gas business is highly competitive in the search for and acquisition of reserves. Our competitors include major oil and gas companies, independent oil and gas companies, financial buyers and individual producers. 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 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 may not always be performed on every platform or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis.

Drilling is a high-risk activity. Our future success will depend on the success of our drilling programs. In addition to the numerous operating risks described in more detail below, these activities involve 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;

equipment failures or accidents; and

compliance with governmental requirements.

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

fires;

explosions;

blow-outs;

- uncontrollable flows of oil, gas, formation water or drilling fluids;
- natural disasters;
- pipe or cement failures;
- casing collapses;
- embedded oilfield drilling and service tools;
- abnormally pressured formations; and
- environmental hazards such as oil spills, natural gas leaks, 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, natural resources and equipment;
- 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 and have caused substantial damage to facilities and interrupt production. Our operations in the Gulf of Mexico are dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. Any significant change affecting these infrastructure facilities could materially harm our business. We deliver crude oil and natural gas through gathering systems and pipelines that we do not own. These facilities may be temporarily unavailable due to adverse weather conditions or may not be available to us in the future. As a result, we could incur substantial liabilities or experience reductions in revenue that could reduce or eliminate the funds available for our exploration and development programs and acquisitions, or result in the loss of properties.

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 fully insurable. As a result of the damage caused by hurricanes in 2005, insurance coverage for these types of storms is limited. Where available, the cost of this insurance coverage may be excessive relative to the risks presented.

Exploration in deepwater involves greater operating and financial risks than exploration at shallower depths. These risks could result in substantial losses. Deepwater drilling and operations require the application of recently developed technologies and involve a higher risk of mechanical failure. We will likely experience significantly higher drilling costs in connection with the deepwater wells that we drill. In addition, much of the deepwater play lacks the physical and oilfield service infrastructure present in shallower waters. As a result, development of a deepwater discovery may be a lengthy process and require substantial capital investment, resulting in significant financial and operating risks.

In addition, 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. The success and timing of drilling and development activities on properties operated by others therefore depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator s expertise and financial resources;
- approval of other participants in drilling wells; and
- selection of technology.

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 type 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 could also 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. We currently have international activities and we continue to evaluate and pursue new opportunities for international expansion in select areas. 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 and 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.

Item 2. ***Properties***

Concentration

Our 10 largest fields accounted for approximately 57% of our proved reserves at year-end 2006. The largest of those fields, the Monument Butte Field, accounted for about 19% of our proved reserves and about 16% of the net present value of our proved reserves at December 31, 2006. Since 2000, we have diversified our asset base, and, as a result, our reserves are more evenly distributed across our focus areas.

Mid-Continent

We have a sizeable presence in the Anadarko and Arkoma Basins. As of December 31, 2006, we owned an interest in more than 825,000 gross acres and about 3,100 gross producing wells. Approximately 130,000 net acres are associated with our Woodford Shale play. The Mid-Continent accounted for approximately 35% of our proved reserves at December 31, 2006. We operate 91% of those reserves.

Onshore Gulf Coast

As of December 31, 2006, we owned an interest in nearly 300,000 gross acres and about 650 gross producing wells primarily along the Gulf Coast of Texas. The onshore Gulf Coast accounted for nearly 20% of our proved reserves at December 31, 2006. We operate about 76% of those reserves.

Rocky Mountains

As of December 31, 2006, we owned an interest in about 221,000 gross acres, 900 gross producing wells and 400 water injection wells. The vast majority of our assets in the Rocky Mountains are in our Monument Butte Field, located in the Uinta Basin of northeastern Utah. We operate 100% of our reserves in the Monument Butte Field. In early 2007, we closed several transactions that added 100,000 gross acres near our Monument Butte Field. The Rocky Mountain division accounted for approximately 20% of our proved reserves at year-end 2006.

Gulf of Mexico

As of December 31, 2006, we owned interests in about 290 leases on the shelf and 70 leases in deepwater (approximately 1.8 million gross acres) and about 617 gross producing wells. We operate about 75% of our Gulf of Mexico reserves. The Gulf of Mexico accounted for approximately 15% of our proved reserves at year-end 2006.

International

At year-end 2006, approximately 10% of our total proved reserves were located internationally.

Malaysia. Through three production sharing contracts, or PSCs, we own interests in three blocks offshore Malaysia. We own a 50% non-operated interest in PM 318 and a 60% operated interest in PM 323. Both blocks are located in shallow water offshore Peninsular Malaysia. PM 318 covers approximately 414,000 gross acres and had gross production of about 7,000 BOPD at year-end 2006. On the same block, we are developing the Abu Field and the 2005 Puteri discovery. PM 323 covers 320,000 acres and has four undeveloped discoveries. Also, we are developing the East Belumut and Chermingat Fields. Offshore Sarawak, we own a 40% operated interest in deepwater Block 2C, a 1.1 million acre area. No production exists on this acreage.

China. We have oil production from two fields on Block 05/36 in Bohai Bay, offshore China. These fields are within a 22,000 gross acre unit in which we have a 12% interest. First production from the fields commenced during 2006. In late 2005, we signed agreements to explore on two blocks offshore Hong Kong in the Pearl River Mouth Basin. We acquired seismic data across portions of the acreage in 2006. The two blocks cover more than 2 million gross acres.

North Sea. Our 2005 Grove discovery is being prepared for production. The field is located on license area 49/10a. We have an 85% interest in this field. At December 31, 2006, we owned interests in about 168,000 gross acres in the U.K. sector.

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, 2006.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
United States:			
Oil and condensate (MMBbls)	61	32	93
Gas (Bcf)	1,094	441	1,535
Total proved reserves (Bcfe)	1,459	633	2,092
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 3,186
International:			
Oil and condensate (MMBbls)	4	17	21
Gas (Bcf)		51	51
Total proved reserves (Bcfe)	25	155	180
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 261
Total:			
Oil and condensate (MMBbls)	65	49	114
Gas (Bcf)	1,094	492	1,586
Total proved reserves (Bcfe)	1,484	788	2,272
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 3,447

(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 $5.36 per Mcf for gas and $51.49 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 Unaudited 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. As a requirement of our credit facility, independent reserve engineers prepare separate reserve reports with respect to properties holding at least 70% of the present value of our proved reserves. At December 31, 2006, the independent reserve engineers reports covered properties representing 83% of our proved reserves and

87% of the present value. For such properties, the reserves reported by the independent reserve engineers were within 3% of the reserves we reported. Actual quantities of recoverable reserves and future cash flows from those reserves most likely will vary from the estimates set forth above. Reserve and cash flow estimates rely on interpretations of data and require many assumptions that may turn out to be inaccurate. For a discussion of these interpretations and assumptions, see *Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves most likely will vary from our estimates* under Item 1A of this report.

Drilling Activity

The following table sets forth our drilling activity for each year in the three-year period ended December 31, 2006.

	2006		2005		2004	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory wells:						
United States:						
Productive[(1)]	420	290.5	390	296.3	211	151.8
Nonproductive[(2)]	36	21.1	32	23.3	22	13.9
United Kingdom:						
Productive[(3)]	1	0.9	1	1.0		
Nonproductive[(4)]			1	0.6	1	1.0
Malaysia:						
Productive[(5)]	10	4.9	4	2.0		
Nonproductive[(6)]	3	1.6	2	1.0		
International Total:						
Productive	11	5.8	5	3.0		
Nonproductive	3	1.6	3	1.6	1	1.0
Exploratory Well Total	470	319.0	430	324.2	234	166.7
Development wells:						
United States:						
Productive	199	183.2	135	116.1	43	37.1
Nonproductive	3	2.7	1	1.0	1	1.0
China:						
Productive	14	1.7				
Nonproductive						
United Kingdom:						
Productive	1	0.9				
Nonproductive						
International Total:						
Productive	15	2.6				
Nonproductive						
Development Well Total	217	188.5	136	117.1	44	38.1

(1)

Includes 62 gross (52.6 net), 27 gross (17.5 net) and 23 gross (14.1 net) wells in 2006, 2005 and 2004, respectively, that are not exploitation wells.

(2) Includes 16 gross (10.8 net), 16 gross (10.0 net) and 17 gross (11.0 net) wells in 2006, 2005 and 2004, respectively, that are not exploitation wells.

(3) The well in 2005 is not an exploitation well.

(4) These wells are not exploitation wells.

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

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

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We were in the process of drilling 25 gross (20.4 net) exploratory wells (includes 22 gross (18.3 net) exploitation wells) and five gross (3.9 net) development wells in the United States, two gross (0.2 net) development wells in China, one gross (0.5 net) development well in Malaysia and one gross (0.9 net) development well in the United Kingdom at December 31, 2006.

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, 2006 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	92	64.9	10	2.2	102	67.1
Gas	395	274.8	120	36.5	515	311.3
Louisiana:						
Oil	5	4.3			5	4.3
Gas	19	12.0	14	4.5	33	16.5
Texas:						
Oil	32	26.9	16	5.1	48	32.0
Gas	536	486.6	288	116.5	824	603.1
Oklahoma:						
Oil	323	239.5	588	21.4	911	260.9
Gas	1,315	1,139.1	589	109.8	1,904	1,248.9
Utah:						
Oil	1,356	1,140.7	9	2.9	1,365	1,143.6
Gas	20	15.0			20	15.0
Other domestic:						
Oil	3	2.8	2	0.7	5	3.5
Gas	10	7.2	24	4.3	34	11.5
Total domestic:						
Oil	1,811	1,479.1	625	32.3	2,436	1,511.4
Gas	2,295	1,934.7	1,035	271.6	3,330	2,206.3
International:						
Offshore China:						
Oil			15	1.8	15	1.8
Offshore Malaysia:						
Oil			10	5.0	10	5.0
Total International:						
Oil			25	6.8	25	6.8

Total:						
Oil	1,811	1,479.1	650	39.1	2,461	1,518.2
Gas	2,295	1,934.7	1,035	271.6	3,330	2,206.3
Total	4,106	3,413.8	1,685	310.7	5,791	3,724.5

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

Acreage Data

As of December 31, 2006, 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:				
Shelf	717	398	253	136
Treasure Project			479	167
Deepwater	46	9	259	114
Total Gulf of Mexico	763	407	991	417
Onshore:				
Louisiana	4	2	1	
Texas	173	104	186	130
Oklahoma	562	328	188	114
Utah	39	32	94	61
Other domestic	15	6	92	79
Total onshore	793	472	561	384
Total domestic	1,556	879	1,552	801
International:				
Offshore Brazil			206	206
Offshore China	22	3	2,266	2,266
Offshore Malaysia	15	8	1,814	970
Offshore United Kingdom			168	146
Total international	37	11	4,454	3,588
Total	1,593	890	6,006	4,389

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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 317,811 gross (99,380 net) undeveloped acres. These interests do not expire.

	Undeveloped Acres Expiring (In thousands)									
	2007		2008		2009		2010		2011	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States:										
Gulf of Mexico:										
Shelf	41	20	69	49	32	18	26	24	15	15
Treasure Project	30	8	263	69	57	17	41	11	5	1
Deepwater	58	26	6	1			35	12	17	13
Total Gulf of Mexico	129	54	338	119	89	35	102	47	37	29
Onshore	125	85	138	93	74	53	9	10	52	51
Total domestic	254	139	476	212	163	88	111	57	89	80
International:										
Offshore Brazil	206	206								
Offshore China	510	510			439	439				
Offshore Malaysia					398	199	338	196	1,079	575
Offshore United Kingdom					77	70			20	17
Total international	716	716			914	708	338	196	1,099	592
Total	970	855	476	212	1,077	796	449	253	1,188	672

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. Individual properties may be subject to burdens that we believe do not materially interfere with the use, or affect the value, of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;

development obligations under oil and gas leases;

burdens such as net profits interests; and

capital commitments under production sharing contracts or exploration licenses.

Item 3. ***Legal Proceedings***

We have been named as a defendant in a number of 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.

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 2006.

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

The following table sets forth the names and ages (as of February 28, 2007) 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	58	Chairman, President and Chief Executive Officer and a Director	12
David F. Schaible	46	Executive Vice President Operations and Acquisitions and a Director	17
Terry W. Rathert	54	Senior Vice President, Chief Financial Officer and Secretary	17
Michael D. Van Horn	55	Senior Vice President Exploration	–
W. Mark Blumenshine	48	Vice President Land	5
Mona Leigh Bernhardt	40	Vice President Human Resources	7
Lee K. Boothby	45	Vice President Mid-Continent	7
Stephen C. Campbell	38	Vice President Investor Relations	7
George T. Dunn	49	Vice President Gulf Coast	14
John H. Jasek	37	Vice President Gulf of Mexico	6
James J. Metcalf	49	Vice President Drilling	11
Gary D. Packer	44	Vice President Rocky Mountains	11
William D. Schneider	55	Vice President International	17
Mark J. Spicer	47	Vice President Information Technology	6
James T. Zernell	49	Vice President Production	10
Brian L. Rickmers	38	Controller and Assistant Secretary	13
Susan G. Riggs	49	Treasurer	10

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

David A. Trice was appointed Chairman in September 2004.

David F. Schaible was promoted from Vice President to Executive Vice President in November 2004. He has served as a director since May 2002.

Terry W. Rathert was promoted from Vice President to Senior Vice President in November 2004.

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

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

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

Lee K. Boothby was promoted to Vice President in November 2004. He has managed our Mid-Continent operations since February 2002.

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

George T. Dunn was promoted to Vice President in November 2004. He has managed our onshore Gulf Coast operations since 2001.

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John H. Jasek was promoted from General Manager to Vice President in November 2006. He has managed our Gulf of Mexico operations since March 2005. Prior to that, 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.

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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
2005		
First Quarter	38.43	27.43
Second Quarter	41.28	32.03
Third Quarter	50.90	39.00
Fourth Quarter	53.52	39.98
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 (Through February 26, 2007)	45.36	39.30

On February 26, 2007, the last reported sales price of our common stock on the NYSE was $44.20 per share.

As of February 26, 2007, there were approximately 1,900 holders of record of our common stock.

We completed a two-for-one split of our common stock following the close of trading on May 25, 2005. The split was effected by a common stock dividend.

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 indenture 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, 2006.

	Total Number of Shares Purchased	Maximum Number (or Approximate) Dollar Value) of

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	as Part of Publicly Announced Plans or Programs[2]	Shares that May Yet be Purchased Under the Plans or Programs
October 1 October 31, 2006				
November 1 November 30, 2006				
December 1 December 31, 2006	793	$ 48.00		

(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.

(2) On November 20, 2006, we announced a program pursuant to which stockholders owning fewer than 100 shares of our common stock could sell their shares at no cost to them. We did not purchase any shares under the program but we did pay for the costs to administrate the program. The program expired on January 26, 2007.

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Item 5A. ***Stockholder Return Performance Presentation***

The performance graph shown below is being furnished pursuant to Regulation S-K, Item 201(e). As required by applicable rules of the SEC, 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, 2001 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, Cabot Oil & Gas Corporation; Chesapeake Energy Corporation; EOG Resources, Inc., Forest Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc., Pioneer Natural Resources Company; Pogo Producing Company, St. Mary Land & Exploration Company, Stone Energy Corporation, Swift Energy Company, The Houston Exploration Company and XTO Energy Inc.

Total Return Analysis	**12/31/2001**	**12/31/2002**	**12/31/2003**	**12/31/2004**	**12/31/2005**	**12/31/2006**
Newfield Exploration	$ 100.00	$ 101.52	$ 125.39	$ 166.27	$ 281.93	$ 258.73
Peer Group	$ 100.00	$ 106.06	$ 141.20	$ 186.79	$ 291.45	$ 287.35
S&P 500	$ 100.00	$ 77.95	$ 100.27	$ 111.15	$ 116.60	$ 134.87

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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 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,				
	2006	**2005**	**2004**	**2003**	**2002**
	(In millions, except per share data)				
Income Statement Data:					
Oil and gas revenues	$ 1,673	$ 1,762	$ 1,353	$ 1,017	$ 627
Income from continuing operations	591	348	312	211	69
Net income	591	348	312	200	74
Earnings per share:					
Basic					
Income from continuing operations	4.67	2.78	2.68	1.94	0.76
Net income	4.67	2.78	2.68	1.83	0.82
Diluted					
Income from continuing operations	4.58	2.73	2.63	1.88	0.76
Net income	4.58	2.73	2.63	1.78	0.81
Weighted average number of shares outstanding for basic earnings per share	127	125	117	109	90
Weighted average number of shares outstanding for diluted earnings per share	129	128	119	113	99
Cash Flow Data:					
Net cash provided by continuing operating activities	$ 1,384	$ 1,109	$ 997	$ 659	$ 383
Net cash used in continuing investing activities	(1,662)	(1,036)	(1,599)	(615)	(502)
Net cash provided by (used in) continuing financing activities	317	(88)	644	(85)	137
Balance Sheet Data (at end of period):					
Total assets	$ 6,635	$ 5,081	$ 4,327	$ 2,733	$ 2,316
Long-term debt	1,048	870	992	643	710
Convertible preferred securities					144
Reserve Data (at end of period):					
Proved reserves:					
Oil and condensate (MMBbls)	114	102	91	38	34
Gas (Bcf)	1,586	1,391	1,241	1,090	977
Total proved reserves (Bcfe)	2,272	2,001	1,784	1,317	1,181
	$ 3,447	$ 5,053	$ 3,602	$ 2,935	$ 2,247

Present value of estimated future after-tax net cash flows

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 crude oil and natural gas properties. Our domestic areas of operation include the onshore Gulf Coast, the Anadarko and Arkoma Basins of the Mid-Continent, the Uinta Basin of the Rocky Mountains and the Gulf of Mexico. Internationally, we are active offshore Malaysia and China and in the U.K. North Sea.

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.

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

Reserve Replacement. Most of our producing properties have declining production rates. As a result, to maintain and grow our production and cash flow we must locate and develop 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

Revenues. All of our revenues are derived from the sale of our oil and gas production, which includes the effects of the settlement of derivative contracts associated with our production that are accounted for as hedges. Settlement of derivative contracts that are not accounted for as hedges has no effect on our reported revenues. Please see Note 5, Commodity Derivative Instruments and Hedging Activities, to our consolidated

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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 year to year as a result of changes in commodity prices or volumes of production sold. Revenues of $1.7 billion for 2006 were 5% lower than 2005 revenues due to lower gas prices and lower oil production partially offset by higher oil prices and increased gas production.

	Year Ended December 31,		
	2006	**2005**	**2004**
Production[1]:			
United States:			
Natural gas (Bcf)	198.7	190.9	197.6
Oil and condensate (MBbls)	6,218	7,152	6,686
Total (Bcfe)	236.0	233.7	237.7
International:			
Natural gas (Bcf)		0.1	0.6
Oil and condensate (MBbls)	1,097	1,294	879
Total (Bcfe)	6.6	7.9	5.9
Total:			
Natural gas (Bcf)	198.7	191.0	198.2
Oil and condensate (MBbls)	7,315	8,446	7,565
Total (Bcfe)	242.6	241.6	243.6
Average Realized Prices[2]:			
United States:			
Natural gas (per Mcf)	$ 6.47	$ 7.18	$ 5.40
Oil and condensate (per Bbl)	51.40	44.06	36.61
Natural gas equivalent (per Mcfe)	6.80	7.21	5.52
International:			
Natural gas (per Mcf)	$	$ 4.71	$ 4.38
Oil and condensate (per Bbl)	56.58	55.68	44.26
Natural gas equivalent (per Mcfe)	9.43	9.20	7.07
Total:			
Natural gas (per Mcf)	$ 6.47	$ 7.17	$ 5.39
Oil and condensate (per Bbl)	52.18	45.84	37.50
Natural gas equivalent (per Mcfe)	6.87	7.27	5.55

(1) Represents volumes sold regardless of when produced.

(2) Average realized prices include the effects of hedging other than contracts that are not designated for hedge accounting. Had we included the effect of these contracts, our average realized price for total gas would have been $7.22, $6.65 and $5.36 per Mcf for 2006, 2005 and 2004, respectively. Our total oil and condensate average realized price would have been $50.25, $44.36 and $35.27 per Bbl for 2006, 2005 and 2004, respectively. Without the effects of hedging contracts, our average realized prices for 2006, 2005 and 2004 would have been $6.42, $7.54 and $5.75 per Mcf, respectively, for gas and $59.13, $53.36 and $40.95 per barrel, respectively, for oil.

Production. Our 2006 total oil and gas production (stated on a natural gas equivalent basis) was essentially the same as total production for 2005. Successful drilling efforts in the Mid-Continent were offset by continued Gulf of Mexico production deferrals of approximately 16 Bcfe during 2006 related to Hurricanes Katrina and Rita in 2005, natural field declines and the timing of liftings of oil production in Malaysia. Our 2005 total oil and gas production (stated on a natural gas equivalent basis) decreased 1% from 2004. The

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decrease was a result of Gulf of Mexico production deferrals of approximately 22 Bcfe related to the 2005 storms offset by a full year s production from our 2004 acquisitions and successful drilling efforts.

Natural Gas. Our 2006 natural gas production increased 4% over 2005. The increase was primarily 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 field declines. Our 2005 natural gas production decreased 4% when compared to 2004. The decrease was the result of production deferrals related to the 2005 storms and natural field declines offset by a full year s production from our 2004 acquisitions.

Crude Oil and Condensate. Our 2006 oil and condensate production decreased 13% primarily as a result of the timing of liftings of oil production in Malaysia. Our 2005 oil and condensate production increased 12% when compared to 2004 primarily due to a full year s production from the Inland Resources acquisition and a full year of liftings in Malaysia partially offset by production deferrals related to the 2005 storms.

Operating Expenses. Generally, our proved reserves and production have grown steadily since our founding. As a result, our operating expenses also have increased. 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.

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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			Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2006	2005		2006	2005	
	(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	$ 2.40	$ 1.90	26%	$ 16	$ 15	5%
Production and other taxes	1.77	0.82	116%	12	6	81%
Depreciation, depletion and amortization	2.00	1.36	47%	13	11	23%
General and administrative	1.28	0.44	191%	8	3	144%
Ceiling test writedown	0.94	1.22	(23%)	6	10	(35%)
Total operating expenses	8.39	5.74	46%	55	45	22%
Total:						
Lease operating	$ 1.14	$ 0.85	34%	$ 277	$ 205	36%
Production and other taxes	0.25	0.26	(4%)	61	64	(5%)
Depreciation, depletion and amortization	2.57	2.15	20%	624	521	20%
General and administrative	0.51	0.43	19%	124	104	18%
Ceiling test writedown	0.03	0.04	(25%)	6	10	(35%)
Other	(0.04)	(0.12)	(67%)	(11)	(29)	(63%)
Total operating expenses	4.46	3.61	24%	1,081	875	24%

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

Lease operating expense (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 impacted by the difference ($0.07 per Mcfe) between insurance proceeds received from the settlement of all claims related to the 2005 hurricanes 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 amount, our LOE would have been $1.04 per

Mcfe for 2006.

Production and other taxes decreased primarily due to refunds related to production tax exemptions on certain of our onshore high cost gas wells in Texas.

The increase in our depreciation, depletion and amortization (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. Please see

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Note 1, Organization and Summary of Significant Accounting Policies *Asset Retirement Obligations*, to our consolidated financial statements.

General and administrative (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 11, 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 of direct internal costs as compared to $38 million in 2005.

Other expenses for 2006 and 2005 include the following items:

In 2006, we redeemed all $250 million 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 related to the notes. In addition, we recorded a $37 million benefit from our business interruption insurance coverage in 2006 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 46% 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 FPSO.

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

DD&A increased as a result of higher cost reserve additions in Malaysia and initial liftings of oil production in China during the third quarter of 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.

Year ended December 31, 2005 compared to December 31, 2004

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2005.

	Unit-of-Production Year Ended December 31, 2005	Unit-of-Production Year Ended December 31, 2004	Percentage Increase (Decrease)	Amount Year Ended December 31, 2005	Amount Year Ended December 31, 2004	Percentage Increase (Decrease)
	(Per Mcfe)			(In millions)		
United States:						
Lease operating	$ 0.81	$ 0.60	35%	$ 190	$ 143	33%
Production and other taxes	0.25	0.17	47%	58	40	44%
Depreciation, depletion and amortization	2.18	1.95	12%	510	463	10%
General and administrative	0.43	0.34	26%	101	82	24%
Other	(0.12)	0.15	(180%)	(29)	35	(181%)
Total operating expenses	3.55	3.21	11%	830	763	9%
International:						
Lease operating	$ 1.90	$ 1.59	19%	$ 15	$ 9	61%
Production and other taxes	0.82	0.38	116%	6	2	183%
Depreciation, depletion and amortization	1.36	1.37	(1%)	11	9	35%
General and administrative	0.44	0.43	2%	3	2	36%
Ceiling test writedown	1.22	2.90	(58%)	10	17	(44%)
Total operating expenses	5.74	6.67	(14%)	45	39	15%
Total:						
Lease operating	$ 0.85	$ 0.63	35%	$ 205	$ 152	35%
Production and other taxes	0.26	0.17	53%	64	42	51%
Depreciation, depletion and amortization	2.15	1.94	11%	521	472	10%
General and administrative	0.43	0.34	26%	104	84	24%
Ceiling test writedown	0.04	0.07	(43%)	10	17	(44%)
Other	(0.12)	0.14	(186%)	(29)	35	(181%)
Total operating expenses	3.61	3.29	10%	875	802	9%

Domestic Operations. Our domestic operating expenses for 2005, stated on an Mcfe basis, increased 11% over the same period of 2004. This increase was primarily related to the following items:

LOE was adversely impacted by deferred production of approximately 22 Bcfe related to the 2005 storms, higher operating costs, increased well workover activity and natural field declines in our Gulf of Mexico properties.

Production and other taxes increased due to higher commodity prices and an increase in the proportion of our production volumes subject to production taxes as a result of our acquisition of the Monument Butte Field, increased production from our Mid-Continent and onshore Gulf Coast operations and storm related deferrals in the Gulf of Mexico.

The increase in our DD&A rate resulted from higher cost reserve additions. The component of DD&A associated with accretion expense related to our asset retirement obligation was $0.06 per Mcfe and $0.05 per Mcfe for 2005 and 2004, respectively.

The increase in G&A expense was primarily due to growth in our workforce as a result of acquisitions and an increase in incentive compensation as a result of higher adjusted net income (as defined in our incentive compensation plan) in 2005 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 2005, we capitalized $38 million of direct internal costs as compared to $30 million in 2004.

Other expenses for 2005 and 2004 include the following items:

In December 2005, we recorded a $22 million benefit related to our business interruption insurance coverage as a result of the disruptions in our operations caused by Hurricanes Katrina and Rita.

As a result of our acquisition of EEX Corporation in November 2002, we owned a 60% interest in a floating production system, some offshore pipelines and a processing facility located at the end of the pipelines in shallow water. At the time of acquisition, we estimated the fair value of these assets to be $35 million. Since their acquisition, we had undertaken to sell these assets. In December 2004, when what we believed was the last commercial opportunity for sale was not realized, we determined that there was no active market for these assets. As a result, in connection with the preparation of our financial statements for the year ended December 31, 2004, we recorded an impairment charge of $35 million. In early April 2005, we entered into an agreement with Diamond Offshore Services Company to sell our interest in the floating production facility and related equipment. In August 2005, we closed the sale and received net proceeds of $7 million, which were recorded as a gain on our consolidated statement of income.

International Operations. In May 2004, we entered into PSCs with Malaysia s state-owned oil company with respect to two offshore blocks. Liftings of oil production began in August 2004. Prior thereto, our producing international operations consisted of one field in the U.K. North Sea, which we sold in June 2005.

The increase in LOE primarily resulted from a full year of operations in Malaysia in 2005.

Production and other taxes increased due to the significant increase in oil prices during 2005.

A ceiling test writedown of $10 million associated with our decreased emphasis on exploration efforts in Brazil and in other non-core international regions was recorded in December 2005. In 2004, we recorded a ceiling test writedown of $17 million associated with a dry hole in the U.K. North Sea.

Interest Expense. The following table presents information about our interest expense for each of the years in the three-year period ended December 31, 2006.

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Gross interest expense	$ 87	$ 72	$ 58
Capitalized interest	(44)	(46)	(26)
Net interest expense	$ 43	$ 26	$ 32

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. The 2005 increase is primarily due to an entire year of accrued interest related to our 65/8% Senior Subordinated Notes due 2014 issued in August 2004 in connection with our acquisition of the Monument Butte Field.

During the second half of 2004, we financed the cash consideration for our acquisitions of properties in Oklahoma and the Gulf of Mexico (aggregating approximately $226 million) primarily with borrowings under our credit arrangements. By the end of the second quarter of 2005, we had repaid all of the borrowings under our credit arrangements for the 2004 acquisitions.

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We capitalize interest with respect to unproved properties. Interest capitalized increased in 2005 over 2004 primarily due to an increase in our unproved property base as a result of the Inland Resources acquisition in late August 2004.

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, 2006.

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Cash flow hedges:			
Hedge ineffectiveness	$ 5	$ (8)	$ 4
Other derivative contracts:			
Realized (loss) on settlement of discontinued cash flow hedges		(51)	
Unrealized gain (loss) due to changes in fair market value	249	(202)	(4)
Realized gain (loss) on settlement	135	(61)	(24)
Total commodity derivative income (expense)	$ 389	$ (322)	$ (24)

Hedge ineffectiveness is associated with our hedging contracts that qualify for hedge accounting under SFAS No. 133. As a result of the production deferrals experienced in the Gulf of Mexico related to Hurricanes Katrina and Rita, hedge accounting was discontinued during the third quarter of 2005 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. 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, 2006, 2005 and 2004 were 38%, 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 excess of the Malaysia and U.K. statutory tax rates over the U.S. federal statutory rate. In addition, our effective tax rate for 2006 increased as a result of an $18 million ($15 million U.K. and $3 million Brazilian) valuation allowance for deferred tax assets related to net operating loss carryforwards in those countries that are not expected to be realized. The $15 million U.K. valuation allowance is due to a substantial decrease in estimated future taxable income as a result of the disappointing results of the recent #7 well in our Grove field in the U.K. North Sea.

Our effective tax rate for the year 2005 was less than our effective tax rate for 2004 primarily due to the realization of a net change of $5 million in our valuation allowance for tax assets related to certain of our international operations. An $8 million valuation allowance related to our U.K. net operating loss carryforwards was reversed in 2005 as a result of a substantial increase in estimated future taxable income as a result of our 2005 Grove discovery in the U.K. North Sea. In 2005, we recorded a $3 million valuation allowance for various international and Brazilian deferred tax assets related to net operating loss carryforwards that were not expected to be realized.

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. Over the long-term, we have successfully grown our reserve base and production, resulting in growth in our net cash flows from operating activities. Fluctuations in commodity prices and the 2005 hurricanes have been the primary reason for short-term changes in our cash flow from operating activities.

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.

We establish a capital budget at the beginning of each calendar year based in part on expected cash flow from operations for that year. In the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. Because of the nature of the properties we own, contractual capital commitments beyond 2007 are not significant. Our 2007 capital budget exceeds currently expected cash flow from operations by approximately $350 million. We anticipate that the shortfall will be made up with cash and short-term investments on hand and borrowings under our credit arrangements.

On October 15, 2007, our 7.45% Senior Notes with an aggregate principal amount of $125 million become due. We currently plan to fund the repayment with borrowings under our credit arrangements.

Credit Arrangements. In December 2005, we entered into a revolving credit facility that matures in December 2010. Our credit facility provides for initial loan commitments of $1 billion from a syndication of participating banks, led by JPMorgan Chase as the agent bank. The loan commitments may be increased to a maximum aggregate amount of $1.5 billion if the current lenders increase their loan commitments or new financial institutions are added to the credit facility. Loans under our credit facility bear interest, at our option, based on (a) a rate per annum equal to the higher of the prime rate or the weighted average of the rates on overnight federal funds transactions 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 (100 basis points per annum at December 31, 2006). At February 26, 2007, we had no outstanding borrowings and $52 million of undrawn letters of credit under our credit facility.

The 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, depreciation, depletion and amortization expense, exploration and abandonment expense and other noncash charges and expenses to consolidated interest expense of at least 3.5 to 1.0; and, as long as our debt rating is below investment grade, the maintenance of an annual ratio of the net present value of our oil and gas properties to total debt of at least 1.75 to 1.00. At December 31, 2006, we were in compliance with all of our debt covenants.

We also have a total of $110 million of borrowing capacity under money market lines of credit with various banks. At February 26, 2007, we had outstanding borrowings of $45 million under our money market lines.

As of February 26, 2007, we had approximately $951 million of available borrowing capacity under our credit arrangements.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements. Generally, we use excess cash to pay down borrowings under our credit arrangements. As a result, we often have a working capital deficit or a relatively small amount of positive working capital. We had a working capital deficit of $272 million as of December 31, 2006. This compares to working capital deficits of $130 million at the end of 2005 and $82 million at the end of 2004. The majority of the working capital deficit at December 31, 2006 relates to the reclassification of our $125 million 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 towards 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 working capital balances are also affected by fluctuations in the fair value of our outstanding commodity derivative instruments. At December 31, 2006, the fair value of our short-term derivatives was a net asset of $200 million. At December 31, 2005, this amount was a net short-term derivative liability of $89 million. At December 31, 2004, the fair value of our short-term derivatives was a net asset of $8 million (see Note 5, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements). Our 2006 working capital deficit also includes $40 million in asset retirement obligations compared to $47 million in 2005 and $23 million in 2004 (see Note 1, Organization and Summary of Significant Accounting Policies *Asset Retirement Obligations*, to our consolidated financial statements).

Cash Flows from Operations. Cash flows from operations are primarily affected by production and commodity prices, net of the effects of settlements of our derivative contracts. Our cash flows from operations also are impacted by changes in working capital. We sell substantially all of our natural gas and oil production under floating market contracts. However, we enter into commodity hedging arrangements to reduce our exposure to fluctuations in natural gas and oil prices, to help ensure that we have adequate cash flow to fund our capital programs and to manage price risks and returns on some of our acquisitions and drilling programs. See Item 7A, *Quantitative and Qualitative Disclosures About Market Risk.* 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 $1,384 million 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.

Our net cash flows from operations were $1,109 million in 2005, an 11% increase over the prior year. Although our 2005 production volumes were impacted by the 2005 storms, higher commodity prices offset the cash flow impact of the deferred production. 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 25% over 2004. See Results of Operations above.

Capital Expenditures. Our 2006 capital spending was $1,890 million, a 69% increase from our 2005 capital spending of $1,119 million. These amounts exclude recorded asset retirement obligations of $16 million in 2006 and $44 million in 2005. During 2006, we invested $1,161 million in domestic exploitation and development, $379 million in domestic exploration (exclusive of exploitation and leasehold activity), $71 million in other domestic leasehold activity and $279 million internationally.

Our 2005 capital spending was $1,119 million, a 38% decrease from our 2004 capital spending of $1,796 million (excluding recorded asset retirement obligations of $48 million). During 2005, we invested $696 million in domestic exploitation and development, $257 million in domestic exploration (exclusive of exploitation and leasehold activity), $81 million in other domestic leasehold activity and $85 million internationally.

We budgeted $1.8 billion for capital spending in 2007, excluding acquisitions. This total includes $50 million for continuing hurricane repairs in the Gulf of Mexico and excludes $100 million for capitalized interest and overhead. Approximately 24% of the $1.8 billion is allocated to the Gulf of Mexico (including the traditional shelf, the deep and ultra-deep shelf and deepwater), 19% to the onshore Gulf Coast, 38% to the Mid-Continent, 8% to the Rocky Mountains and 11% to international projects. See Item 1, *Business* Plans for 2007. Since our 2007 capital budget exceeds currently forecasted cash flow, we plan to make up the shortfall with borrowings under our credit arrangements. Actual levels of capital expenditures may vary significantly due to many factors, including the extent to which proved 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. Historically, with the exception of 2006, we have completed several acquisitions of varying sizes each year. 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 flows provided by financing activities for 2006 were $317 million compared to $88 million of net cash flows used in financing activities for 2005.

In October 2007, our $125 million principal amount 7.45% Senior Notes will become due. We currently anticipate repaying these notes with borrowings under our credit arrangements.

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During 2006, we:

- issued $550 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2016;
- used the proceeds from this offering to redeem $250 million principal amount of our 83/8% Senior Subordinated Notes due 2012;
- borrowed and repaid $519 million under our credit arrangements; and
- received proceeds of $15 million from the issuance of shares of our common stock.

During 2005, we:

- repaid a net $120 million under our credit arrangements; and
- received proceeds of $32 million from the issuance of shares of our common stock.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of December 31, 2006.

	Total	Less Than 1 Year	1-3 Years	4-5 Years	More Than 5 Years
			(In millions)		
Debt:					
7.45% Senior Notes due 2007	$ 125	$ 125	$	$	$
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	1,175	125		175	875
Other obligations:					
Interest payments	566	79	214	118	155
Net derivative (assets) liabilities	(44)	(203)	159		
Asset retirement obligations	272	40	94	34	104
Operating leases(1)	190	80	91	8	11
Deferred acquisition payments(2)	9	3	4	2	
Oil and gas activities(3)	257				
Total other obligations	1,250	(1)	562	162	270
Total contractual obligations	$ 2,425	$ 124	$ 562	$ 337	$ 1,145

(1) See Note 14, Commitments and Contingencies *Lease Commitments*, to our consolidated financial statements.

(2) See Note 3, Acquisitions, to our consolidated financial statements.

(3) See *Oil and Gas Activities* below.

Oil and Gas Activities. 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, 2006, these work related commitments total $257 million and are comprised of $160 million in the United States and $97 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 October 1997, we issued $125 million aggregate principal amount of our 7.45% Senior Notes due 2007. 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.

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

incur debt secured by certain liens;

enter into sale/leaseback transactions; and

enter into merger or consolidation transactions.

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

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 September 1, 2007, we may redeem up to 35% of the original principal amount of our 65/8% notes due 2014 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. Likewise, before April 15, 2009, we may redeem up to 35% of the original principal amount of our 65/8% notes due 2016 with similar net cash proceeds at 106.625% of the principal amount plus accrued and unpaid interest to the date of redemption.

The indenture governing our senior subordinated notes limits 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;

make certain dispositions of assets;

engage in transactions with affiliates; and

engage in mergers, consolidations and certain sales 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

We generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 12-24 months as part of our risk management program. In the case of 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. 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. Approximately 57% of our 2006 production was subject to derivative contracts (including both contracts that are designated and not designated for hedge accounting). In 2005, 81% of our production was subject to derivative contracts, compared to 72% in 2004.

While the use of hedging arrangements limits the downside risk of adverse price movements, they 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, all 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. Therefore, we believe that our hedged production is not subject to material basis risk. 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 $0.70 - $0.80 less per MMBtu 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 production from our operations in Malaysia typically sells at Tapis, or about even with WTI. Oil sales from our operations in China are currently averaging about $15 per barrel less than the 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, 2006, Bank of Montreal, JPMorgan Chase, Citibank, N.A. and J Aron & Company were the counterparties with respect to 73% of our future hedged production.

Please see the discussion and tables in Note 5, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements for a description of the accounting applicable to our hedging program and a listing of open contracts as of December 31, 2006 and the fair value of those contracts as of that date.

Between January 1, 2007 and February 26, 2007, we entered into additional natural gas price derivative contracts set forth in the table below.

		NYMEX Contract Price per MMBtu				
			Collars			
		Swaps	Floors		Ceilings	
Period and Type of Contract	**Volume in MMMBtus**	**(Weighted Average)**	**Range**	**Weighted Average**	**Range**	**Weighted Average**
January 2007 March 2007						
Price swap contracts	590	$ 7.16				
April 2007 June 2007						
Price swap contracts	1,820	7.70				
July 2007 September 2007						
Price swap contracts	1,230	7.77				
October 2007 December 2007						
Price swap contracts	920	8.80				
Collar contracts	8,235		$ 8.00	$ 8.00	$ 10.00 - $11.85	$ 10.68
January 2008 March 2008						
Price swap contracts	910	9.29				
Collar contracts	12,285		8.00	8.00	10.00 - 11.85	10.68
April 2008 June 2008						
Price swap contracts	1,820	7.67				
July 2008 September 2008						
Price swap contracts	1,840	7.67				
October 2008 December 2008						
Price swap contracts	620	7.67				

None of the contracts above have been designated for hedge accounting.

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 *Oil and Gas Activities*.

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 judgements.

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 exploration costs to be expensed as they are incurred 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 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. As a requirement of our revolving credit facility, independent reserve engineers prepare separate reserve reports with respect to properties holding at least 70% of the present value of our proved reserves. For December 31, 2006, the independent reserve engineers reports covered properties representing 83% of our proved reserves and 87% of the present value. For such properties, the reserves reported by the independent reserve engineers were within 3% of the reserves we reported.

Depreciation, Depletion and Amortization. Estimated proved oil and gas reserves are a significant component of our calculation of depletion 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 2006 would require a decrease in our estimated proved reserves at December 31, 2005 of approximately 13 Bcfe. Due to the relatively small size of our international full cost pools for the U.K., 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 less than 5% of our consolidated production for 2006, 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 amortization expense in future periods. The ceiling limitation is applied separately for each country in which we have oil and gas properties. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. 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, 2006, the ceiling value of our domestic oil and gas reserves was calculated based upon quoted market prices of $5.64 per MMBtu for gas and $61.05 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties would have exceeded the ceiling amount by approximately $5 million (net of tax) at December 31, 2006. However, on February 22, 2007, the market price for gas (Gas Daily Henry Hub) increased to $7.48 per MMBtu and the market price for oil (Platt s WTI at Cushing) decreased to $60.95 per barrel. Utilizing these prices, the unamortized costs of our domestic oil and gas properties would not have exceeded the ceiling amount at December 31, 2006. As a result, we did not record a writedown in the fourth quarter of 2006. The ceiling with respect to our oil and gas properties in the U.S. using the

February 22, 2007 prices exceeded the net capitalized costs of those properties by approximately $900 million.

At December 31, 2006, the ceiling with respect to our oil and gas properties in Malaysia, the U.K. and China exceeded the net capitalized costs of the properties by approximately $68 million, $11 million and $19 million, respectively. Due to the relatively small size of these international pools, holding all other factors constant, if the applicable index for natural gas prices were to decline to approximately $4.80 per Mcf and/or oil prices were to decline to approximately $50 per Bbl, it is possible that we could experience ceiling test writedowns in one or all of these international areas.

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 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 future 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, 2006, our domestic full cost pool had approximately $906 million of costs excluded from the amortization base, including $26 million associated with development costs for our deepwater Gulf of Mexico project known as Glider, located at Green Canyon 247/248. At December 31, 2006, capital costs not subject to amortization include $292 million related to our acquisition of the Monument Butte Field. Due to the significant size of the field, evaluation of the entire amount will require a number of years. Because the application of the full cost ceiling test at December 31, 2006 (before considering the natural gas price increases experienced subsequent to year end) resulted in an excess of the carrying value of our domestic oil and gas properties over the cost-center ceiling, inclusion of some or all of our unevaluated property costs in our amortization base would have further increased the excess of the carrying value over the cost-center ceiling. Utilizing commodity prices in effect as of February 22, 2007, the inclusion of some or all of these 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.

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 abandonment and development 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, 2006 would require an increase in the present value of our estimated future abandonment and development costs at December 31, 2005 of approximately $40 million. Due to the relatively small size of our international full cost pools in the U.K., Malaysia and China, any change in future abandonment or development costs associated with the respective country s full cost pool would significantly change the DD&A rate in that country. However, since production from our International operations represented less than 5% of our consolidated production for 2006, 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 the acquisition of oil and gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and gas reserves and unproved properties. To the extent the consideration paid exceeds the fair value of the net assets acquired, we are required to record the excess as an asset called goodwill. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain. The value allocated to recoverable oil and gas reserves and unproved properties is subject to the cost center ceiling as described under *Full Cost Ceiling Limitation* above.

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.