NEWFIELD EXPLORATION CO /DE/
Form 10-K/A
February 28, 2007

Table of Contents

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

Form 10-K/A
(Amendment No. 2)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2005

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 $5 billion as of June 30, 2005 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of March 1, 2006, there were 128,502,719 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 4, 2006, which is incorporated by reference into Part III of this Form 10-K.

Table of Contents

EXPLANATORY NOTE

We are filing this amendment to our annual report for the year ended December 31, 2005 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 3, 2006, the original filing date of our annual report for the year ended December 31, 2005.

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 the following:

To add the definition of exploitation well ;

To revise the definition of development well to exclude exploitation wells, which results in exploitation wells being included in the definition of exploration or exploratory well ;

To revise various portions of the report to reflect the shift of exploitation wells and activities from development wells and activities to exploration wells and activities, including the Drilling Activity table on page 11, the Oil and Gas Properties table on page 65 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 88;

To reference the applicable Regulation S-X Rules in our definitions of proved developed reserves, proved reserves and proved undeveloped reserves ;

To revise our revenue recognition policy in Note 1, *Revenue Recognition* to our consolidated financial statements to address all of the criteria set forth in SAB Topic 13:1; and

To clarify in the table on page 90 that substantially all of our purchases of properties during 2003 relate to our August 2004 acquisition of Inland Resources.

The following table reflects the changes made to the Drilling Activities table on page 11 as a result of the revisions to the definition of development well. Positive numbers indicate the number of wells added to a category and negative numbers indicate the number of wells removed from a category.

	2005		2004		2003	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory wells:						
United States:						
Productive	363	278.8	188	137.7	98	64.9
Nonproductive	16	13.3	5	2.9	4	1.4
China:						
Productive						
Nonproductive						

United Kingdom:						
Productive						
Nonproductive						
Malaysia:						
Productive	3	1.5				
Nonproductive						
Total	382	293.6	193	140.6	102	66.3
Development wells:						
United States:						
Productive	(363)	(278.8)	(188)	(137.7)	(98)	(64.9)
Nonproductive	(16)	(13.3)	(5)	(2.9)	(4)	(1.4)
Total	(382)	(293.6)	(193)	(140.6)	(102)	(66.3)

The following table reflects the changes made to the table in Note 5, *Oil and Gas Properties* on page 65 as a result of the revisions to the definition of development well. Positive numbers indicate amounts added to a category and negative numbers indicate amounts removed from a category.

	December 31, 2005	December 31, 2004	December 31, 2003
		(In millions)	
Exploration in progress	91	31	31
Development in progress	(91)	(31)	(31)

The following table reflects the changes made to the table in our Supplementary Oil and Gas Disclosures Unaudited on page 88 as a result of the revision to the definition of development well. 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
2005:						
Property acquisitions:						
Unproved	$	$	$	$	$	$
Proved						
Exploration	551	1	6	1		559
Development	(551)	(1)	(6)	(1)		(559)
Total costs incurred	$	$	$	$	$	$
2004:						
Property acquisitions:						
Unproved	$	$	$	$	$	$
Proved						
Exploration	482					482
Development	(482)					(482)
Total costs incurred	$	$	$	$	$	$
2003:						
Property acquisitions:						
Unproved	$	$	$	$	$	$
Proved						
Exploration	253					253
Development	(253)					(253)
Total costs incurred	$	$	$	$	$	$

TABLE OF CONTENTS

Table of Contents

Table of Contents

If you are not familiar with any of the oil and gas terms used in this report, we have provided explanations of many of them under the caption Commonly Used Oil and Gas Terms at the end of 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 initially focused on the shallow waters of the Gulf of Mexico. Today, we have a diversified asset base. 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.

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.

At year-end 2005, we had proved reserves of 2.0 Tcfe. Of those reserves:

- 70% were natural gas;
- 68% were proved developed;
- 72% were located onshore in the U.S.;
- 20% were located in the Gulf of Mexico; and
- 8% were located internationally.

The location of our reserves has changed significantly since the late 1990s. Through large acquisitions, leasing efforts and subsequent drilling activities, we have added significant reserves onshore in the U.S. We also have added international focus areas and have grown reserves through these ventures.

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 drillbit, 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 Rocky Mountains, the Mid-Continent and the shallow waters of Malaysia and the Gulf of Mexico are complemented with higher potential plays in the Gulf of Mexico s deep and ultra-deep shelf and deepwater and in other international waters. In recent years, about 20-30% of our initial annual capital expenditure budget has been allocated to exploration (exclusive of exploitation) activities. We actively look for new drilling ideas on our existing property base and on properties that may be acquired. In 2005, 96% 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 drillbit is a critical consideration in our acquisition screening process. Since 2000, we have made several large acquisitions that have helped establish new focus areas. Recently, higher commodity prices and stiff competition for acquisitions has significantly increased the cost of available properties. As a result, during the past year we have looked to alternative ways to gain access to oil and gas properties such as joint venture alliances and leasing efforts.

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 2005, we operated about 79% of our total production.

Technology. By investing in technology, we give our people the tools they need to succeed. Over the last five years, we have invested about $165 million in the acquisition of new seismic data. We have seismic surveys covering all of our major areas of operation.

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 28, 2006, our employees owned or had options to acquire about 7% of our outstanding common stock on a fully diluted basis.

Focus Areas

Onshore Gulf Coast. We established onshore Gulf Coast operations in 1995 and made major acquisitions in 2000 and 2002 to grow our presence. Today, the onshore Gulf Coast is a major focus area for us, representing about one quarter of our total proved reserves and 30% of our daily production. Our operations are concentrated in South Texas, East Texas and the Val Verde Basin of West Texas.

Mid-Continent. Through an acquisition in January 2001, we added the Mid-Continent as a focus area. Since that time, we have doubled our proved reserves and production from this area. The Mid-Continent is a gas-rich province characterized by multiple productive zones and relatively low drilling costs. For the past several years, we have focused on an initiative that we call gas mining. We drilled 267 wells in the Mid-Continent in 2005 and have a multi-year inventory of lower risk drilling opportunities. Our Mid-Continent division is managed by our Tulsa, Oklahoma office.

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 nearly 200 wells in the field in 2005 and expect to drill a similar number in 2006. The multiple basins of the Rocky Mountains, which have significant remaining reserves, offer us opportunities for growth. 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 believe that significant opportunities remain in the deep shelf and ultra-deep shelf. We operate about 180 production platforms in shallow water. This infrastructure facilitates cost effective operations and timely development of our discoveries. In the deepwater, we have made four deepwater discoveries to date, two of which are under development. First production from one of the discoveries is expected in late 2006.

We also are active in an exploration initiative we refer to as Treasure Project. Prospective drilling depths for this concept are 30,000 feet or more. The ultra-deep targets of this concept are high risk but the potential reserve impact could be significant. We have 95 lease blocks associated with this concept. There is no production from these depths on the Gulf of Mexico shelf today. In February 2005, we began drilling the first test of this concept the Blackbeard West #1 well. The well continues to drill. Initially, our cost to drill the well was carried by our partners; however, the well s cost has exceeded initial estimates so we are now paying 23% of the costs. We estimate that our net cost for the well will be approximately $15 million.

International. Over the last two years, we have acquired interests in three offshore Malaysia blocks that 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 expect to drill our first deepwater prospect in late 2006. We are developing two oil fields in China s Bohai Bay. First production is expected in late 2006. During 2005, we added two license areas offshore Hong Kong in the Pearl River Mouth Basin. In the North Sea, we are developing our 2005 Grove discovery with first production expected in late 2006. We have international offices in Kuala Lumpur, London and Beijing.

For revenues from our domestic and international operations, see Note 17, Segment Information, to our consolidated financial statements appearing later in this report.

Plans for 2006

Our capital budget for 2006 is $1.9 billion, including $180 million allocated for hurricane repairs in the Gulf of Mexico (of which we expect the majority to be covered by proceeds from insurance) and $105 million of capitalized interest and overhead. We have not budgeted for potential acquisitions. We plan to drill more than 600 wells in 2006, about 80% of which are lower risk wells in the Mid-Continent or the Uinta Basin. About $350 million has been earmarked for exploration (exclusive of exploitation) activities.

Onshore Gulf Coast. In 2006, we will balance development drilling of lower risk opportunities with some higher risk, higher impact exploration tests. We plan to drill about 100 wells and invest approximately $350 million.

Mid-Continent. We expect to drill about 300 wells and invest approximately $440 million. The majority of the planned drilling is associated with our gas mining initiatives.

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 220 wells in the field during 2006. We also plan to drill 4-8 deep gas exploratory wells to test for potential beneath the field. Our 2006 capital budget includes $155 million for these activities.

Gulf of Mexico. We expect to drill about 25-30 wells in 2006, including 15-20 in the traditional shelf, 3-4 in the deep shelf, one (Blackbeard West #1) in the ultra-deep Treasure Project and 3-5 in deepwater. About $375 million of our capital budget for 2006 has been allocated for these drilling projects.

International. In 2006, we expect to drill 10-12 shallow water wells in Malaysia and one deepwater exploration well. In the North Sea, we plan to drill two development wells in our Grove Field and one exploration well. Our drilling program in the Bohai Bay will focus on development of our two commercial fields. Our total investment in these international ventures for 2006 is planned to be $300 million.

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

Table of Contents

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 current market prices. Oil sales contracts are based upon posted prices plus negotiated bonuses. 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. Because alternative purchasers of oil and gas are readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on us.

Refining capacity for the crude oil we produce from our Monument Butte Field in the Uinta Basin could be limited. Please see the discussion under the caption *We may not achieve continued production growth from our Monument Butte Field* in Item 1A of this report.

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 March 1, 2006, we had 762 employees. All but 46 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.

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 is subject to periodic redeterminations based in part on 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;

weather conditions;

the level of consumer demand;

the price of foreign imports;

world-wide economic conditions;

political conditions in oil and gas producing regions; and

domestic and foreign governmental regulations.

Table of Contents

Our use of oil and gas price hedging contracts involves credit risk and may limit future revenues from price increases and result in significant fluctuations in our net income. We use hedging transactions with respect to a portion of our oil and gas production to achieve more predictable cash flow and to reduce our exposure to price fluctuations. 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. We follow the provisions of Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, which generally requires us to record each hedging transaction as an asset or liability measured at its fair value. Each period, we must record changes in the fair value of our hedges, which could result in significant fluctuations in net income and stockholders equity from period to period.

Our future success depends on our ability to find, develop and acquire oil and gas reserves. As is generally the case, our producing properties in the Gulf of Mexico and the onshore Gulf Coast often have high initial production rates, followed by steep declines. 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.

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 hedge positions) 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 continued production growth from our Monument Butte Field. In August 2004, we acquired Inland for approximately $575 million in cash. Inland s primary asset is the 100,000-acre Monument Butte Field located in the Uinta Basin of Northeast Utah. Waterflooding, a secondary recovery operation that involves the injection of large volumes of water into the oil-producing reservoir, is necessary to recover the oil reserves in the field. We must negotiate with third parties to obtain additional sources of water. The crude oil produced in the Uinta Basin is known as black wax and 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. Our ability to significantly increase production from the field may be limited by the unavailability of sufficient water supplies or refining capacity or both. In addition, the price we receive for our production from the field could be adversely affected by the availability for refining of crude oil from other basins.

Competitive industry conditions may negatively affect our ability to conduct operations. Competition in the oil and gas industry is intense, particularly with respect to access to drilling rigs and other services, the acquisition of properties and the hiring and retention of technical personnel. Recently, higher commodity prices and stiff competition for acquisitions has 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;
- 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 discovered. 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:

- adverse weather conditions;
- unexpected drilling conditions;
- pressure or irregularities in formations;

- equipment failures or accidents;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

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 and discharges of toxic gases.

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 cause 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 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 may be unavailable or limited.

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

Table of Contents

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 exploitation 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.

Other independent oil and gas companies limited access to capital may change our exploration and development plans. Many independent oil and gas companies have limited access to the capital necessary to finance their activities. As a result, some of the other working interest owners of our wells may be unwilling or unable to pay their share of the costs of projects as they become due. These problems could cause us to change, suspend or terminate our drilling and development plans with respect to the affected project.

Our certificate of incorporation, stockholder rights plan and bylaws 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. These provisions could potentially deprive our stockholders of opportunities to sell shares of our common stock at above-market prices.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

Concentration

Our 10 largest fields accounted for approximately 48% of our proved reserves at year-end 2005. The largest of those fields, Monument Butte Field, accounted for about 20% of our proved reserves and about 14% of the net present value of our proved reserves at December 31, 2005. We have diversified our asset base. Only 20% of our year-end 2005 proved reserves were located in the Gulf of Mexico compared to 98% just six years ago.

Onshore Gulf Coast

As of December 31, 2005, we owned an interest in nearly 250,000 gross acres and about 570 gross producing wells primarily along the Gulf Coast of Texas. The onshore Gulf Coast accounted for nearly 25% of our proved reserves at December 31, 2005. We operate about 75% of those reserves.

Mid-Continent

We have a sizeable presence in the Anadarko and Arkoma Basins. As of December 31, 2005, we owned an interest in more than 800,000 gross acres and about 2,600 gross producing wells. The Mid-Continent accounted for about 30% of our proved reserves at December 31, 2005. We operate 87% of those reserves.

Rocky Mountains

As of December 31, 2005, we owned an interest in about 170,000 gross acres, 740 gross producing wells and 330 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.

Gulf of Mexico

As of December 31, 2005, we owned interests in about 300 leases on the shelf and 70 leases in deepwater (approximately 1.9 million gross acres) and about 220 gross producing wells. We operate about 78% of our Gulf of Mexico reserves.

International

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 10,000 BOPD at year-end 2005. On the same block, we are developing the Abu Field, with estimated first production in early 2007, and the 2005 Puteri discovery, with first production expected in late 2007. PM 323 covers 320,000 acres and has four undeveloped discoveries. We are developing the East Belumut and Chermingat Fields with first production expected in 2008. Offshore Sarawak, we own a 60% operated interest in deepwater Block 2C, a 1.1 million acre area. No production exists on this acreage.

China. We are participating in the development of two commercial oil 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 is expected to begin in the second half of 2006. In late 2005, we signed agreements to explore on two blocks offshore Hong Kong in the Pearl River Mouth Basin. The two blocks cover more than 2 million gross acres.

North Sea. We are developing Grove, a 2005 field discovery. The field is located on license area 49/10a and is expected to produce about 60 MMcfe/d from three wells. First production is expected in the fourth quarter of 2006. We have a 100% interest in this field. At December 31, 2005, 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, 2005.

		Proved Reserves	
	Developed	**Undeveloped**	**Total**
United States:			
Oil and condensate (MMBbls)	54.6	31.9	86.5
Gas (Bcf)	1,010.2	317.0	1,327.2
Total proved reserves (Bcfe)	1,338.0	508.2	1,846.2
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 4,734
International:			
Oil and condensate (MMBbls)	4.3	10.8	15.1
Gas (Bcf)		64.1	64.1
Total proved reserves (Bcfe)	25.8	128.9	154.7
			$ 319

Present value of estimated future after-tax net cash flows (in millions)[1]			
Total:			
Oil and condensate (MMBbls)	58.9	42.7	101.6
Gas (Bcf)	1,010.2	381.1	1,391.3
Total proved reserves (Bcfe)	1,363.8	637.1	2,000.9
Present value of estimated future after-tax net cash flows (in millions)[1]			$ 5,053

Table of Contents

(1) This measure was prepared using year-end oil and gas prices adjusted for the location and quality of the reserves, discounted at 10% per year. Weighted average year-end prices, as so adjusted, were $8.08 per Mcf for gas and $56.50 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, 2005, the independent reserve engineers reports covered properties representing 81% of our proved reserves and 82% of the present value. For such properties the reserves were within 3% of the reserves we reported for such properties. 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, 2005.

	2005		**2004**		**2003**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory wells:						
United States:						
Productive(1)	390	296.3	211	151.8	125	81
Nonproductive(2)	32	23.3	22	13.9	28	15.8
China:						
Productive(4)					2	0.7
Nonproductive(4)					1	0.4
United Kingdom:						
Productive(4)	1	1.0				
Nonproductive(4)	1	0.6	1	1.0		
Malaysia:						
Productive(3)	4	2.0				
Nonproductive(4)	2	1.0				
Total	430	324.2	234	166.7	156	97.9
Development wells:						
United States:						
Productive	135	116.1	43	37.1	41	27.5
Nonproductive	1	1.0	1	1.0	2	1.4
Total	136	117.1	44	38.1	43	28.9

(1) Includes 27 gross (17.5 net), 23 gross (14.1 net) and 27 gross (16.1 net) wells in 2005, 2004 and 2003, respectively, that are not exploitation wells.

(2) Includes 16 gross (10.0 net), 17 gross (11.0 net) and 24 gross (14.4 net) wells in 2005, 2004 and 2003, respectively, that are not exploitation wells.

(3) These wells are not exploitation wells.

(4) Includes 1 gross (0.5 net) wells in 2005, that are not exploitation wells.

We were in the process of drilling 3 gross (2.3 net) development wells and 39 gross (25.3 net) exploitation wells in the United States, one gross (1.0 net) appraisal well in the United Kingdom and two gross (0.2 net) development wells in China at December 31, 2005.

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, 2005 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	37	31.4	7	1.4	44	32.8
Gas	128	107.1	50	14.9	178	122.0
Louisiana:						
Oil	2	1.8			2	1.8
Gas	11	7.0	9	2.4	20	9.4
Texas:						
Oil	24	19.4	16	4.2	40	23.6
Gas	430	386.6	240	91.5	670	478.1
Oklahoma:						
Oil	238	180.7	574	20.4	812	201.1
Gas	1,041	782.7	530	96.0	1,571	878.7
Utah:						
Oil	735	617.2	2	0.4	737	617.6
Gas						
Other domestic:						
Oil	2	1.0	1	0.3	3	1.3
Gas	9	6.8	23	3.9	32	10.7
Total domestic:						
Oil	1,038	851.5	600	26.7	1,638	878.2
Gas	1,619	1,290.2	852	208.7	2,471	1,498.9
International:						
Offshore Malaysia:						
Oil			10	5.0	10	5.0
Total:						

Oil	1,038	851.5	610	31.7	1,648	883.2
Gas	1,619	1,290.2	852	208.7	2,471	1,498.9
Total	2,657	2,141.7	1,462	240.4	4,119	2,382.1

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements or production sharing contracts. The operator supervises production, maintains

Table of Contents

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

We own 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. The following table shows certain information regarding our developed and undeveloped acreage as of December 31, 2005.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
	(In thousands)			
United States:				
Gulf of Mexico:				
Shelf	750	416	322	194
Treasure Project			474	176
Deepwater	58	13	294	115
Total Gulf of Mexico	808	429	1,090	485
Onshore:				
Louisiana	12	7	2	1
Texas	167	103	136	100
Oklahoma	517	318	200	136
Utah	43	36	107	83
Other domestic	12	5	29	11
Total onshore	751	469	474	331
Total domestic	1,559	898	1,564	816
International:				
Offshore Brazil			206	206
Offshore China	22	3	2,266	2,266
Offshore Malaysia	6	3	1,812	1,046
Offshore United Kingdom			168	168
Total international	28	6	4,452	3,686
Total	1,587	904	6,016	4,502

Table of Contents

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, will hold acreage beyond the expiration date. We own fee mineral interests in 237,091 gross (98,998 net) undeveloped acres. These interests do not expire.

	Undeveloped Acres Expiring									
	2006		2007		2008		2009		2010	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(In thousands)									
United States:										
Gulf of Mexico:										
Shelf	62	47	62	36	62	54	17	17	26	26
Treasure Project	50	50	30	8	263	69	57	17	38	10
Deepwater	63	24	58	12	6				35	16
Total Gulf of Mexico	175	121	150	56	331	123	74	34	99	52
Onshore	129	109	101	95	33	51	5	5	3	5
Total domestic	304	230	251	151	364	174	79	39	102	57
International:										
Offshore Brazil			86	86			30	30		
Offshore China			510	510						
Offshore Malaysia							414	207	319	191
Offshore United Kingdom							77	77		
Total international			596	596			521	314	319	191
Total	304	230	847	747	364	174	600	353	421	248

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.

Table of Contents

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 2005.

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

The following table sets forth the names and ages (as of February 28, 2006) 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	57	Chairman, President and Chief Executive Officer and a Director	11
David F. Schaible	45	Executive Vice President Operations and Acquisitions and a Director	16
Elliott Pew	51	Executive Vice President Exploration	8
Terry W. Rathert	53	Senior Vice President, Chief Financial Officer and Secretary	16
W. Mark Blumenshine	47	Vice President Land	4
Mona Leigh Bernhardt	39	Vice President Human Resources	6
Lee K. Boothby	44	Vice President Mid-Continent	6
Stephen C. Campbell	37	Vice President Investor Relations	6
George T. Dunn	48	Vice President Gulf Coast	13
James J. Metcalf	48	Vice President Drilling	10
Gary D. Packer	43	Vice President Rocky Mountains	10
William D. Schneider	54	Vice President International	16
Mark J. Spicer	46	Vice President Information Technology	5
James T. Zernell	48	Vice President Production	9
Brian L. Rickmers	37	Controller and Assistant Secretary	12
Susan G. Riggs	48	Treasurer	9

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.

Elliott Pew was promoted from Vice President to Executive Vice President in November 2004.

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

W. Mark Blumenshine was promoted from Manager to Vice President in December 2005. He served as Manager-Land since joining us in 2001. Prior to that, he worked for Dominion Exploration & Production Company as General Manager Land.

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. From August 1999 through January 2002, he managed our Australian operations.

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

Table of Contents

George T. Dunn was promoted to Vice President Gulf Coast in November 2004. He has managed our onshore Gulf Coast operations since 2001. Prior to that, he was the General Manager of our Western Gulf of Mexico operations.

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.

Brian L. Rickmers has served as Controller and Assistant Secretary since May 2001. From February 2000 to May 2001, he served as Assistant Controller.

Table of Contents

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
2004		
First Quarter	25.10	22.08
Second Quarter	28.36	23.46
Third Quarter	31.41	26.29
Fourth Quarter	32.92	27.88
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 (Through February 28, 2006)	54.50	38.18

On February 28, 2006, the last reported sales price of our common stock on the NYSE was $38.65 per share.

As of February 28, 2006, there were approximately 3,000 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 83/8% Senior Subordinated Notes due 2012 and our 65/8% Senior Subordinated Notes due 2014 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, 2005.

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

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Shares Purchased as Part of Publicly Announced Plans or Programs	Shares that May Yet Be Purchased Under the Plans or Programs
October 1 October 31, 2005				
November 1 November 30, 2005				
December 1 December 31, 2005	1,412	$ 49.31		

(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, nor do we have a publicly announced program to repurchase shares of our common stock.

Table of Contents

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,				
	2005	**2004**	**2003**	**2002**	**2001**
	(In millions, except per share data)				
Income Statement Data:					
Oil and gas revenues	$ 1,762	$ 1,353	$ 1,017	$ 627	$ 714
Income from continuing operations	348	312	211	69	117
Net income	348	312	200	74	119
Earnings per share:					
Basic					
Income from continuing operations	2.78	2.68	1.94	0.76	1.33
Net income	2.78	2.68	1.83	0.82	1.35
Diluted					
Income from continuing operations	2.73	2.63	1.88	0.76	1.27
Net income	2.73	2.63	1.78	0.81	1.28
Weighted average number of shares outstanding for basic earnings per share	125	117	109	90	89
Weighted average number of shares outstanding for diluted earnings per share	128	119	113	99	98
Cash Flow Data:					
Net cash provided by continuing operating activities	$ 1,109	$ 997	$ 659	$ 383	$ 496
Net cash used in continuing investing activities	(1,036)	(1,599)	(615)	(502)	(755)
Net cash provided by (used in) continuing financing activities	(88)	644	(85)	137	273
Balance Sheet Data (at end of period):					
Total assets	$ 5,081	$ 4,327	$ 2,733	$ 2,316	$ 1,663
Long-term debt	870	992	643	710	429
Convertible preferred securities				144	144
Reserve Data (at end of period):					
Proved reserves:					
Oil and condensate (MMBbls)	101.6	90.5	37.8	34.0	31.0
Gas (Bcf)	1,391	1,241	1,090	977	718
Total proved reserves (Bcfe)	2,001	1,784	1,317	1,181	904
Present value of estimated future after-tax net cash flows	$ 5,053	$ 3,602	$ 2,935	$ 2,247	$ 959

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 to reduce our exposure to commodity price fluctuations.

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; and
- the value of our derivative positions.

Results of Operations

In 2005, four storms caused production deferrals in the Gulf of Mexico Dennis, Arlene, Katrina and Rita. The full year 2005 impact of these storms was a deferral of approximately 22 Bcfe of production from the Gulf of Mexico. The damage to infrastructure, pipelines and processing facilities continues to impact our Gulf of Mexico production. We are currently producing about 215 MMcfe/d and have about 90 MMcfe/d of deliverability offline. We expect that Gulf production will reach 250 MMcfe/d by the end of the first quarter of 2006 and 270 MMcfe/d by mid-year. Production in 2006 also will be negatively impacted by the deferral of drilling and recompletions programs that were scheduled in the third and fourth quarters of 2005. We expect that deferrals associated with hurricanes will be about 15 Bcfe in 2006.

We completed several significant acquisitions during the second and third quarters of 2004. As described in more detail below, these acquisitions had a meaningful impact on our 2005 and 2004 results of operations and cash flows. In May 2004, we entered into Production Sharing Contracts (PSCs) with Malaysia s state-owned oil company in partnership with its exploration and production subsidiary. Liftings of oil production in

Table of Contents

Malaysia began in August 2004. In July 2004, we acquired producing oil and gas properties in Oklahoma. Also in July 2004, we acquired all of the outstanding stock of Denbury Offshore, Inc., the subsidiary of Denbury Resources Inc. that held substantially all of its Gulf of Mexico assets. In August 2004, we acquired Inland Resources Inc. These acquisitions were financed through cash on hand, borrowings under our credit arrangements and offerings of our common stock and our 65/8% Senior Subordinated Notes due 2014. See Note 4, Acquisitions, Note 8, Debt, and Note 10, Common Stock Activity, to our consolidated financial statements set forth in Item 8 in this report for a full discussion of these activities.

In September 2003, we sold our wholly owned subsidiary, Newfield Exploration Australia Ltd., which held all of our Australian assets. As a result of the sale, the historical results of our Australian operations are reflected on our consolidated financial statements as discontinued operations. Please see Note 2, Discontinued Operations, to our consolidated financial statements. Except where noted, discussions in this report relate to our continuing activities.

Revenues. All of our revenues are derived from the sale of our oil and gas production, which is net of the effects of the settlement of qualifying hedging contracts associated with our production. Settlement of our derivative contracts that do not qualify for hedge accounting has no effect on our reported revenues. Our revenues may vary significantly from year to year as a result of changes in commodity prices or production volumes. Revenues for 2005 reached a record $1.8 billion and were 30% higher than 2004 revenues due to a substantial increase in natural gas and crude oil prices, successful drilling efforts in the onshore Gulf Coast and Mid-Continent areas and a full year s production in 2005 from our Inland Resources acquisition and a full year s liftings in Malaysia. This increase was partially offset by our Gulf of Mexico production deferrals of approximately 22 Bcfe caused by storms in 2005.

Table of Contents

	Year Ended December 31,		
	2005	2004	2003
Production[1]:			
United States:			
Natural gas (Bcf)	190.9	197.6	184.2
Oil and condensate (MBbls)	7,152	6,686	6,054
Total (Bcfe)	233.7	237.7	220.6
International:			
Natural gas (Bcf)	0.1	0.6	
Oil and condensate (MBbls)	1,294	879	
Total (Bcfe)	7.9	5.9	
Total:			
Natural gas (Bcf)	191.0	198.2	184.2
Oil and condensate (MBbls)	8,446	7,565	6,054
Total (Bcfe)	241.6	243.6	220.6
Average Realized Prices[2]:			
United States:			
Natural gas (per Mcf)	$ 7.18	$ 5.40	$ 4.60
Oil and condensate (per Bbl)	44.06	36.61	27.99
Natural gas equivalent (per Mcfe)	7.21	5.52	4.61
International:			
Natural gas (per Mcf)	$ 4.71	$ 4.38	$
Oil and condensate (per Bbl)	55.68	44.26	
Natural gas equivalent (per Mcfe)	9.20	7.07	
Total:			
Natural gas (per Mcf)	$ 7.17	$ 5.39	$ 4.60
Oil and condensate (per Bbl)	45.84	37.50	27.99
Natural gas equivalent (per Mcfe)	7.27	5.55	4.61

(1) Represents volumes sold regardless of when produced.

(2) Average realized prices include the effects of hedging other than contracts that do not qualify for hedge accounting. Had we included the effect of these contracts, our average realized price for total gas would have been $6.65 per Mcf and $5.36 per Mcf for 2005 and 2004, respectively. Our total oil and condensate average realized price would have been $44.36 per Bbl and $35.27 per Bbl for 2005 and 2004, respectively. There were no contracts that did not qualify for hedge accounting that settled in 2003.

Production. Our 2005 total oil and gas production (stated on a natural gas equivalent basis) decreased 1% from 2004. The decrease was a result of the 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. Our 2004 total oil and gas production increased 10% over 2003. The increase was primarily the result of our PNR acquisition in September 2003, the Oklahoma property and Denbury Offshore acquisitions in July 2004, the Inland acquisition in August 2004 and successful drilling efforts in the onshore Gulf Coast and Mid-Continent areas. In addition, liftings in Malaysia began during the third quarter of 2004. These increases were partially offset by shut-in production of approximately 2.5 Bcfe during the third quarter of 2004 in the Gulf of Mexico due to Hurricane Ivan and natural field declines.

Table of Contents

Natural Gas. 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. Our 2004 natural gas production increased 8% when compared to 2003. The increase primarily was the result of our 2004 acquisitions and successful drilling efforts. The increase was partially offset by shut-in production during the third quarter of 2004 due to Hurricane Ivan and natural field declines.

Crude Oil and Condensate. Our 2005 oil and condensate production increased 12% as a result of 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. Our 2004 oil and condensate production increased 25% when compared to 2003 primarily due to initial production and liftings in Malaysia and the Inland Resources acquisition in the third quarter of 2004.

Effects of Hedging on Realized Prices. The following table presents information about the effects of hedging on realized prices.

	Average Realized Prices		Ratio of Hedged to Non-Hedged Price(2)
	With Hedge(1)	Without Hedge	
Natural Gas:			
Year ended December 31, 2005	$ 7.17	$ 7.54	95%
Year ended December 31, 2004	5.39	5.75	94%
Year ended December 31, 2003	4.60	5.15	89%
Crude Oil and Condensate:			
Year ended December 31, 2005	$ 45.84	$ 53.36	86%
Year ended December 31, 2004	37.50	40.95	92%
Year ended December 31, 2003	27.99	30.10	93%

(1) Average realized prices include the effects of hedging other than contracts that do not qualify for hedge accounting. Had we included the effect of these contracts, our average realized price for total gas would have been $6.65 per Mcf and $5.36 per Mcf for 2005 and 2004, respectively. Our total oil and condensate average realized price would have been $44.36 per Bbl and $35.27 per Bbl for 2005 and 2004, respectively. There were no contracts that did not qualify for hedge accounting that settled in 2003.

(2) The ratio is determined by dividing the realized price (which includes the effects of hedging other than those contracts that do not qualify for hedge accounting) by the price that otherwise would have been realized without hedging activities.

Operating Expenses. We are a growth-oriented company. As such, our proved reserves and production have grown steadily since our founding. Naturally, our operating expenses have increased with our growth. As a result, 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.

Table of Contents

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 (Per Mfe)			Amount (In millions)		
	Year Ended December 31,		Percentage Increase	Year Ended December 31,		Percentage Increase
	2005	2004	(Decrease)	2005	2004	(Decrease)
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:

Lease operating expense (LOE), on an Mcfe basis, 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, on an Mcfe basis, 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 Inland Resources, increased production from our Mid-Continent and onshore Gulf Coast operations and storm related deferrals in the Gulf of Mexico.

Table of Contents

The increase in our depreciation, depletion and amortization (DD&A) resulted from higher cost reserve additions. The component of DD&A associated with accretion expense related to SFAS No. 143 was $0.06 per Mcfe and $0.05 per Mcfe for 2005 and 2004, respectively. The component of DD&A associated with furniture, fixtures and equipment was $0.01 per Mcfe for 2005 and 2004.

The increase in general and administrative expense (G&A) for 2005 of $0.09 per Mcfe, or 26%, 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 operations disruptions 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.

Year ended December 31, 2004 compared to December 31, 2003

Our Australian operations were sold in September 2003 and have been excluded from our reported operations for the year ended December 31, 2003. Other international operations for 2003 were immaterial and are not reported separately.

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2004.

	Unit-of-Production (Per Mcfe)			Amount (In millions)		
	Year Ended December 31,		Percentage Increase	Year Ended December 31,		Percentage Increase
	2004	2003	(Decrease)	2004	2003	(Decrease)
United States:						
Lease operating	$ 0.60	$ 0.57	5%	$ 143	$ 125	14%
Production and other taxes	0.17	0.14	21%	40	32	26%
Depreciation, depletion and amortization	1.95	1.79	9%	463	395	17%
General and administrative	0.34	0.28	21%	82	62	33%
Other	0.15	0.09	67%	35	20	71%
Total operating expenses	3.21	2.87	12%	763	634	20%
International:						
Lease operating	$ 1.59			$ 9		
Production and other taxes	0.38			2		
Depreciation, depletion and amortization	1.37			9		
General and administrative	0.43			2		
Ceiling test writedown	2.90			17		
Total operating expenses	6.67			39		
Total:						
Lease operating	$ 0.63	$ 0.57	11%	$ 152	$ 125	21%
Production and other taxes	0.17	0.14	21%	42	32	33%
Depreciation, depletion and amortization	1.94	1.79	8%	472	395	19%
General and administrative	0.34	0.28	21%	84	62	36%
Ceiling test writedown	0.07		N/M(1)	17		N/M(1)
Other	0.14	0.09	56%	35	20	71%
Total operating expenses	3.29	2.87	15%	802	634	26%

(1) Not meaningful.

Domestic Operations. Our domestic operating expenses for 2004, stated on an Mcfe basis, increased 12% over the same period of 2003. This increase was primarily related to the following items:

LOE, on an Mcfe basis, increased in 2004 as a result of higher operating costs and natural field declines in our Gulf of Mexico properties.

Production and other taxes, on an Mcfe basis, increased in 2004 due to higher commodity prices and an increase in our production volumes subject to production taxes.

The increase in our DD&A for 2004 resulted from higher cost reserve additions. The component of DD&A associated with accretion expense related to SFAS No. 143 was $0.05 per Mcfe and $0.03 per Mcfe for 2004 and 2003, respectively. The component of DD&A associated with furniture, fixtures and equipment was $0.01 per Mcfe and $0.03 per Mcfe for 2004 and 2003, respectively.

G&A expense for 2004 increased $0.06 per Mcfe, or 21%. The increase was primarily due to our growing workforce from acquisitions and an increase in incentive compensation expense as a result of the increase in our 2004 profitability over 2003. During 2004, we capitalized $30 million of direct internal costs as compared to $27 million in 2003.

Other expenses for 2004 and 2003 include the following items:

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.

Pursuant to a gas forward sales contract entered into in 1999, EEX committed to deliver approximately 50 Bcf of production to a third party in exchange for proceeds of $105 million. When we acquired EEX, we recorded a liability of $62 million, which represented the then current market value of approximately 16 Bcf of remaining reserves subject to the contract. We accounted for the obligation under the gas sales contract as debt on our consolidated balance sheet. In March 2003, pursuant to a settlement agreement, the gas sales contract and all related agreements were terminated in exchange for a payment by us of approximately $73 million. We recognized a loss of $10 million under the caption Other on our consolidated statement of income as a result of the settlement.

In June 2003, we redeemed all of our outstanding convertible trust preferred securities for an aggregate redemption price of approximately $149 million, including $6 million of optional redemption premium. This premium and $4 million of unamortized offering costs (which were being amortized over the 30-year life of the securities) were expensed under the caption Other on our consolidated statement of income. We financed the redemption with the net proceeds (approximately $131 million) from the issuance and sale of 3.5 million shares of our common stock in May 2003 and borrowings under our credit arrangements.

International Operations. Prior to entering into the Malaysian PSCs, our producing international operations consisted of one field in the U.K. North Sea. Liftings in Malaysia began in the third quarter of 2004. The majority of LOE, production and other taxes and DD&A for 2004 relates to our Malaysian operations. G&A expense is primarily associated with our U.K. North Sea operations and the opening of our office in Malaysia during 2004.

In November 2004, we announced that our Cumbria Prospect in the North Sea was a dry hole. Under full cost accounting, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized in cost centers on a country-by-country basis. Because the unamortized costs exceeded the full cost ceiling, we recognized a ceiling test writedown of $17 million in 2004.

Interest Expense. The following table presents information about our interest expense for each of the years in the three-year period ended December 31, 2005.

	Year Ended December 31,		
	2005	2004	2003
	(In millions)		
Gross interest expense	$ 72	$ 58	$ 58
Capitalized interest	(46)	(26)	(16)
Net interest expense	26	32	42
Distributions on preferred securities			5
Total interest expense and distributions	$ 26	$ 32	$ 47

Gross Interest Expense. The components of gross interest expense for each of the years in the three-year period ended December 31, 2005 are as follows:

	Year Ended December 31,		
	2005	2004	2003
	(In millions)		
Credit arrangements	$ 4	$ 5	$ 4
Senior and subordinated notes	67	53	45
Interest rate swaps		(2)	(1)
Secured notes		1	6
Other	1	1	4
Gross interest expense	$ 72	$ 58	$ 58

The increase in gross interest expense in 2005 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 Inland Resources.

During the second half of 2004, we financed the cash consideration for our Oklahoma property and Denbury Offshore acquisitions (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 facilities for the 2004 acquisition.

During 2003, we entered into interest rate swap agreements with respect to $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 75/8% Senior Notes due 2011. These swap agreements provide for us to pay variable and receive fixed interest payments.

In connection with our 2002 acquisition of EEX, we also assumed $101 million principal amount of secured notes (interest rate of 7.54% per annum) and $62 million under a gas forward sales contract (effective interest rate of

9.5% per annum). During 2003, we repurchased or repaid $74 million principal amount of secured notes. Interest expense for 2003 includes $4 million of premiums paid in connection with repurchases. In January 2004, we repurchased the remainder of the secured notes. We settled the gas forward sales contract in March 2003. The repurchase of secured notes and the settlement of the gas sales obligation were financed with borrowings under our credit arrangements.

Capitalized Interest. We capitalize interest with respect to unproved properties. Interest capitalized increased in 2005 over 2004, and in 2004 over 2003 primarily due to an increase in our unproved property base as a result of the Inland Resources acquisition in late August 2004.

Distributions on Preferred Securities. We redeemed all of our outstanding trust preferred securities in June 2003 with the net proceeds from an offering of our common stock and borrowings under our credit arrangements.

Commodity Derivative Expense. The following table presents information about the components of commodity derivative expense for each of the years in the three-year period ended December 31, 2005.

	Year Ended December 31,		
	2005	2004	2003
	(In millions)		
Cash Flow Hedges:			
Hedge ineffectiveness	$ (8)	$ 4	$ (1)
Derivatives not designated as cash flow hedges:			
Unrealized (loss) on discontinued cash flow hedges	(11)		
Realized (loss) on settlement of discontinued cash flow hedges	(51)		
Unrealized (loss) due to changes in fair market value	(191)	(4)	(5)
Realized (loss) on settlement	(61)	(24)	
Total commodity derivative expense	$ (322)	$ (24)	$ (6)

Hedge ineffectiveness is associated with our hedging contracts that qualify for hedge accounting under SFAS No. 133. As a result of the production deferrals 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, we recorded an $11 million unrealized loss which represents the unrealized hedging loss previously deferred to Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet. The unrealized loss due to changes in fair market value is associated with our derivative contracts that do not qualify for hedge accounting and represents changes in the fair value of our open contracts during the period.

Taxes. The effective tax rates for the years ended December 31, 2005, 2004 and 2003 were 36%, 37% and 36%, respectively. Our effective tax rate was more than the federal statutory tax rate for all three years primarily due to state income taxes associated with income from various states in which we have operations and the excess of the Malaysia statutory tax rate over the U.S. federal statutory rate. 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. The $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 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 are 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.

Cumulative Effect of Change in Accounting Principle Adoption of SFAS No. 143. We adopted SFAS No. 143, Accounting for Asset Retirement Obligations, as of January 1, 2003. This statement changed the method of accounting for expected future costs associated with our obligation to perform site reclamation, dismantle facilities and plug and abandon wells. As a result of our adoption of SFAS No. 143, we recorded a $135 million increase in the net capitalized costs of our oil and gas properties and an initial asset retirement obligation, or ARO, of $129 million. Additionally, we recognized an after-tax gain of $6 million (the after-tax amount by which additional capitalized costs, net of accumulated depreciation, exceeded the initial ARO, including in each case discontinued operations) as the cumulative effect of change in accounting principle. See Note 1, Organization and Summary of Significant

Accounting Policies *Asset Retirement Obligations,* to our consolidated financial statements set forth in Item 8 of this report.

Discontinued Operations

As a result of the sale of our Australian operations in September 2003, the historical financial position, results of operations and cash flow of these operations are reflected in our consolidated financial statements as discontinued operations. The results of our Australian operations for the year ended December 31, 2003 are summarized in Note 2, Discontinued Operations, to our consolidated financial statements.

Liquidity and Capital Resources

We must find new and develop existing reserves to maintain and grow production and cash flow. We add new reserves and grow production through successful exploration and development drilling and the acquisition of properties. These activities require substantial capital expenditures. Historically, we have successfully grown our reserve base and production, resulting in net long-term growth in our cash flow from operating activities. Fluctuations in commodity prices have been the primary reason for short-term changes in our cash flow from operating activities.

We establish a capital budget at the beginning of each calendar year based on expected cash flow from operations for that year. In the past, we often have revised our capital budget during the year as a result of acquisitions or successful drilling. Because of the nature of the properties we own, a substantial majority of our capital budget is discretionary.

We maintain insurance against many of the operating risks associated with exploration and production in the Gulf of Mexico. We believe that the costs to repair and replace platforms, pipelines and wells damaged by Hurricanes Katrina and Rita will be substantially offset by proceeds from physical damage, control of well, operators extra expense and business interruption insurance.

Credit Arrangements. In December 2005, we entered into a revolving credit facility that matures in December 2010. The terms of the credit facility provide for initial loan commitments of $1 billion from a syndication of participating banks, led by JPMorgan Chase as the agent bank. The loan commitments under the credit facility may be increased to a maximum aggregate amount of $1.5 billion if the lenders increase their loan commitments or new financial institutions are added to the credit facility. Loans under the credit facility bear interest, at the option of the Company, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate, substantially equal to the London Interbank Offered Rate (LIBOR), plus a margin that is based on a grid of our debt rating (100 basis points per annum at December 31, 2005). At February 28, 2006, we had no outstanding borrowings under the credit facility.

The credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed .60 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 calculated net present value of our oil and gas properties to total debt of at least 1.75 to 1.00. At December 31, 2005, we were in compliance with all of its debt covenants.

As of February 28, 2006, we had $71 million of undrawn letters of credit under our credit facility. The letters of credit outstanding under the credit facility are subject to annual fees, based on a grid of our debt rating (87.5 basis points at February 28, 2006) plus an issuance fee of 12.5 basis points.

We also have a total of $110 million of borrowing capacity under money market lines of credit with various banks. At February 28, 2006, we had no outstanding borrowings under our money market lines.

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 $130 million as of December 31, 2005. This compares to working capital deficits of $82 million at the end of 2004 and $61 million at the end of 2003. Our working capital deficit is affected by fluctuations in the fair value of our commodity derivative instruments. As of December 31, 2005, we had a net short-term derivative liability of $89 million, a net short-term derivative asset of $8 million at December 31, 2004 and $31 million of net short-term derivative liability at December 31, 2003. Our 2005 working capital deficit also includes $47 million in asset retirement obligations compared to $23 million in 2004 and $12 million in 2003 (see Note 1, Organization and Summary of Significant Accounting Policies *Asset Retirement Obligations,* to our consolidated financial statements). Our 2005 and 2004 working capital deficits include a higher accrued employee incentive payable than in 2003 due to an increase in our 2005 and 2004 net income. Our 2005 and 2004 working capital deficit also includes several deferred acquisition payments related to our 2004 acquisitions (see Note 7, Accrued Liabilities, to our consolidated financial statements).

Cash Flows from Operations. Cash flows from operations is primarily affected by production and commodity prices, net of the effects of hedging. Our cash flows from operations are also 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 hedging arrangements to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. 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.

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 production deferrals related to 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) increased 31% over 2004. See Results of Operations above.

Our net cash flows from operations were $997 million in 2004, a 51% increase over the prior year. The increase was primarily due to a 20% increase in our realized oil and gas prices (on a natural gas equivalent basis) and a 10% increase in production volumes due to our acquisitions during 2004. See Results of Operations above. Accounts payable and accrued liabilities increased $80 million due to the increased levels of development and exploration activities in progress at year-end 2004, our growth from acquisitions during 2004 and higher commodity prices in effect at December 31, 2004.

Capital Expenditures. Our 2005 capital spending was $1,119 million, a 38% decrease from our 2004 capital spending of $1,796 million, excluding asset retirement obligations of $44 million in 2005 and $48 million in 2004. 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.

Our 2004 capital spending of $1,796 million was nearly three times our 2003 capital spending of $647 million (excluding asset retirement obligations of $32 million in 2003). This included $719 million allocated for financial accounting purposes to the oil and gas properties acquired in our $575 million purchase of Inland. This also included approximately $225 million for acquisitions in Oklahoma and the Gulf of Mexico. During 2004, we also invested $570 million in domestic exploitation and development, $191 million in domestic exploration (exclusive of exploitation and leasehold activity), $38 million in other domestic leasehold activity and $102 million internationally. The international capital spending included $49 million related to the acquisition of our Malaysian PSCs.

We budgeted $1.9 billion for capital spending in 2006, excluding acquisitions. The total includes $1.6 billion for new capital projects, $180 million for hurricane repairs in the Gulf of Mexico (substantially all of which will be offset with proceeds from insurance) and $105 million for capitalized interest and overhead. Approximately 23% of the $1.6 billion of capital projects is allocated to the Gulf of Mexico (including the traditional shelf, the deep and ultra-deep shelf and deepwater), 22% to the onshore Gulf Coast, 27% in the Mid-Continent, 9% in the Rocky Mountains and 19% to international projects. See Item 1, *Business* Plans for 2006. To the extent that cash flow from operations during the year is lower than our capital needs, we will 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, size and purchase price of

Table of Contents

acquisitions are unpredictable. Historically, 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 used in financing activities for the year ended December 31, 2005 were $88 million compared to $644 million of net cash flows provided by financing activities for the same period of 2004.

During 2005, we:

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

During 2004, we:

- borrowed a net $25 million under our credit arrangements;
- repurchased $3 million principal amount of secured notes;
- sold 5.4 million shares of our common stock for net proceeds of approximately $277 million, or $52.85 per share; and
- issued $325 million of senior subordinated notes.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of December 31, 2005.

	Total	Less than 1 Year	1-3 Years (In millions)	4-5 Years	More than 5 Years
Debt:					
7.45% Senior Notes due 2007	$ 125	$	$ 125	$	$
75/8% Senior Notes due 2011	175			175	
83/8% Senior Subordinated Notes due 2012	250				250
65/8% Senior Subordinated Notes due 2014	325				325
Total debt	875		125	175	575
Other obligations:					
Interest payments	410	65	175	100	70
Derivative liabilities, net	278	88	146	44	
Asset retirement obligations	260	47	79	43	91
Operating leases[1]	174	47	105	8	14
Deferred acquisition payments[2]	20	5	15		

Oil and gas activities(3)		195								
Total other obligations		1,337		252		520		195		175
Total contractual obligations	$	2,212	$	252	$	645	$	370	$	750

(1) See Note 15, Commitments and Contingencies *Lease Commitments*, to our consolidated financial statements set forth in Item 8 in this report.

(2) See Note 4, Acquisitions, to our consolidated financial statements.

(3) See *Commitments under Joint Operating Agreements* and *Oil and Gas Activities* below.

Credit Arrangements. Please see Liquidity and Capital Resources *Credit Arrangements* above for a description of our bank 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 which 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 2002, we issued $250 million aggregate principal amount of our 83/8% Senior Subordinated Notes due 2012. In August 2004, we issued $325 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2014. 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 the 83/8% notes at any time on or after August 15, 2007 and some or all of the 65/8% notes at any time on or after September 1, 2009, in each case, at a redemption price stated in the applicable indenture governing the notes. We also may redeem all but not part of the 83/8% notes prior to August 15, 2007 and all but not part of the 65/8% notes prior to September 1, 2009, 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 the 65/8% notes 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. The oil and gas industry operates in many instances through joint ventures under joint operating or similar agreements, and our operations are no exception. 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 in the event that the 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 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, 2005, these work related commitments total $195 million and are comprised of $93 million in the United States and $102 million internationally. These items are included in the total column of the Contractual Obligations table above but not included by maturity, as their timing cannot be accurately predicted.

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 81% of our 2005 production was subject to derivative contracts (including both contracts that qualify and do not qualify for hedge accounting under SFAS No. 133, as amended). In 2004, 72% of our production was subject to derivative contracts, compared to 75% in 2003.

While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also 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. The price we receive for our Gulf Coast production typically averages about $2 per barrel below the NYMEX West Texas Intermediate (WTI) price. The price we receive for our production in the Rocky Mountains averages about $6 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 Malaysia typically sells at Tapis, or about even with 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, 2005, Bank of Montreal, JPMorgan Chase, Barclays Bank PLC and J Aron & Company were the counterparties with respect to 77% of our future hedged production.

Please see the discussion and tables in Note 6, 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, 2005 and the fair value of those contracts as of that date.

Table of Contents

Between January 1, 2006 and February 27, 2006, we entered into the 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**
April 2006 June 2006						
Price swap contracts	7,470	$ 8.82				
Collar contracts	5,100		$ 8.00 $9.35	$ 8.27	$ 10.50 $13.70	$ 11.44
July 2006 September 2006						
Price swap contracts	7,470	8.87				
Collar contracts	5,100		8.00 9.35	8.27	10.50 13.70	11.44
October 2006 - December 2006						
Collar contracts	3,660		9.40	9.40	12.15 15.40	13.43
January 2007 - March 2007						
Collar contracts	5,440		9.40	9.40	12.15 15.40	13.43

Between January 1, 2006 and February 27, 2006, we entered into the additional oil price derivative contracts with respect to our future oil production set forth in the table below.

		NYMEX Contract Price Per Bbl				
			Collars			
		Swaps	Floors		Ceilings	
Period and Type of Contract	**Volume in Bbls**	**(Weighted Average)**	**Range**	**Weighted Average**	**Range**	**Weighted Average**
October 2006 December 2006						
Price swap contracts	30,000	$ 70.00				
Collar contracts	60,000		$ 60.00	$ 60.00	$ 80.50 $81.00	$ 80.75
January 2007 December 2007						
Price swap contracts	120,000	70.00				
Collar contracts	240,000		60.00	60.00	80.50 81.00	80.75

None of the above natural gas and oil contracts have been designated as cash flow hedges under SFAS No. 133.

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 in Contractual Obligations *Oil and Gas Activities* above.

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 our audit committee. 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 made by management.

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 stock-based compensation may be accounted for under one of two available methods.

Accounting for commodity derivative activities requires estimates and assumptions regarding the value of derivative positions.

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 and abandonment 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 bank 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, 2005, the independent reserve engineers reports covered properties representing 81% of our proved reserves and 82% of the present value. For such properties, the reserves were within 3% of the reserves we reported for such properties.

Depreciation, Depletion and Amortization. The quantities of 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 the year ended December 31, 2005 would require a decrease in our estimated proved reserves at December 31, 2004 of approximately 10 Bcfe. Due to the relatively small size of our international full cost pools in 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, as our international operations in the U.K. and China were not producing during the year and production from our Malaysian operations represents less than 5% of our consolidated production for 2005, 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 our oil and gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, it would reduce earnings and impact 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. Given the volatility of natural gas and oil prices, it is reasonably possible that our estimate of discounted future net cash flows from proved reserves will change in the near term. If natural gas and oil prices decline, even if for only a short period of time, 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, 2005, the ceiling with respect to our oil and gas properties in the U.S. exceeded the net capitalized costs of those properties by approximately $2.2 billion. 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 $63 million, $150 million and $40 million, respectively, at December 31, 2005. Due to the relatively small size of these international pools, holding all other factors constant, if natural gas prices decline

to a range of $3.25 $3.50 per Mcf and oil prices decline to a range of $45 $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. Unevaluated costs are excluded from our amortization base until we have evaluated the properties associated with these costs. 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 involves 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, 2005, our domestic full cost pool had approximately $840 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, 2005, capital costs not subject to amortization include $316 million related to our acquisition of Inland. Due to the significant size of the Monument Butte Field, acquired in the Inland transaction, evaluation of the entire amount will require a number of years. Because the application of the full cost ceiling test at December 31, 2005 resulted in a significant excess of the cost-center ceiling over the carrying value of our domestic oil and gas properties, inclusion of some or all of our unevaluated property costs in our amortization base, without adding any associated reserves, would not have resulted in a ceiling test writedown. However, our future DD&A rate would increase to the extent such costs are transferred without any associated reserves.

Future Development and Abandonment Costs. Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, market demand for equipment, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future 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

Table of Contents

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, 2005 would require an increase in the present value of our estimated future abandonment and development costs at December 31, 2004 of approximately $25 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 and/or development costs associated with the respective country s full cost pool would significantly change the DD&A rate in that country. However, as our international operations in the U.K. and China were not producing during the year and production from our Malaysian operations represents less than 5% of our consolidated production for 2005, 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 the recoverable oil and gas reserves and unproved properties is subject to the cost center ceiling as described under *Full Cost Ceiling Limitation* above.

Effective January 1, 2002, we adopted SFAS No. 142, Goodwill and Other Intangible Assets, under which goodwill is no longer subject to amortization. Rather, goodwill of each 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.

Stock-Based Compensation

For 2005 there were two alternative methods that could be used to account for stock-based compensation. The first method the intrinsic value method recognizes compensation cost as the excess, if any, of the quoted market price of our stock at the grant date over the amount an employee must pay to acquire the stock. Under the second method the fair value method compensation cost is measured at the grant date based on the value of an award and is recognized over the service period, which is usually the vesting period. Currently, we account for our stock-based compensation in accordance with the intrinsic value method. However, in Note 1, Organization and Summary of Significant Accounting Policies *Stock-Based Compensation,* to our consolidated financial statements we have provided tabular information for each of the years in the three-year period ended December 31, 2005 that compares our net income and earnings per share as reported and on a pro forma basis as if we had used the fair value method of accounting for stock-based compensation. We will adopt the fair value method in the first quarter of 2006. See Note 1, Organization and Summary of Significant Accounting Policies *Stock-Based Compensation,* to our consolidated financial statements.

Commodity Derivative Activities

We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future natural gas and oil production. We generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next 12-24 months. In the case of acquisitions, we may hedge acquired production for a longer period. We do not use derivative instruments for trading purposes. Under the accounting rules, we can elect to designate those derivatives that qualify for hedge accounting as cash flow hedges against the price that we will receive for our future oil and natural gas production. To the extent that changes in the fair values of the cash flow hedges offset changes in the expected cash flows from our forecasted production, such amounts are not included in our consolidated results of operations. Instead, they are recorded directly to stockholders equity until the hedged oil or natural gas quantities are produced and sold. To the extent the change in the fair value of the derivative exceeds the change in the expected cash flows from the forecasted production, the change is recorded in income in the period in which it occurs. Derivatives that do not qualify for (such as three-way collar contracts see Note 6, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements) or have not been designated as cash flow hedges for hedge accounting are carried at their fair value on our consolidated balance sheet. We recognize all changes in the fair value of these contracts on our consolidated statement of income in the period in which the change occurs.

In determining the amounts to be recorded for cash flow hedges, we are required to estimate the fair values of both the derivative and the associated hedged production at its physical location. Where necessary, we adjust NYMEX prices to other regional delivery points using our own estimates of future regional prices. Our estimates are based upon various factors that include closing prices on the NYMEX, over-the-counter quotations, volatility and the time value of options. The calculation of the fair value of our option contracts requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the hedge agreements and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differences and interest rates. We periodically validate our valuations using independent, third-party quotations.

New Accounting Standards

We will adopt SFAS No. 123(R) at the beginning of the first quarter of 2006. We currently expect the adoption of SFAS No. 123(R) will impact our results of operations, but will not impact our financial position. The impact of the adoption of SFAS No. 123(R) on our reported results of operations for future periods will depend on the level of share-based payments granted in the future. However, had we adopted SFAS No. 123(R) in prior periods, the impact of that standard would have approximated the impact of SFAS No. 123 as described in the disclosure of pro forma net income and net income per share in the table included in Note 1, Organization and Summary of Significant Accounting Policies *Stock-Based Compensation*, to our consolidated financial statements.

Regulation

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, local and international regulation. An overview of this regulation is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Please see the discussion under the caption *We are subject to complex laws that can affect the cost, manner or feasibility of doing business* in Item 1A of this report.

Federal Regulation of Sales and Transportation of Natural Gas. Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to several laws enacted by Congress and the regulations promulgated under these laws by the FERC. In the past, the federal government has regulated the prices at which gas could be sold. Congress removed all price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. Congress could, however, reenact price controls in the future.

Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to the FERC s jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation.

The ultimate impact of the complex rules and regulations issued by the FERC since 1985 cannot be predicted. In addition, some aspects of these regulatory developments have not become final but are still pending judicial and FERC final decisions. We cannot predict what further action the FERC will take on these matters. Some of the FERC s more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

The Outer Continental Shelf Lands Act, or OCSLA, requires that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its Natural Gas Act jurisdiction. Therefore, we do not believe that any FERC or MMS action taken under OCSLA will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (2005 EPA). This comprehensive act contains many provisions that will encourage oil and gas exploration and development in the U.S. The 2005 EPA directs the FERC, MMS and other federal agencies to issue regulations that will further the goals set out in the 2005 EPA. We believe that neither the 2005 EPA, nor the regulations promulgated, or to be promulgated, as a result of the 2005 EPA will affect us in a way that materially differs from the way they affect other natural gas producers, gatherers and marketers with which we compete.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Federal Regulation of Sales and Transportation of Crude Oil. Our sales of crude oil and condensate are currently not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products are dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other natural gas producers.

Federal Leases. The majority of our U.S. operations are located on federal oil and gas leases, which are administered by the MMS. These leases are issued through competitive bidding, contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to OCSLA (which are subject to change by the MMS). For offshore operations, lessees must obtain MMS approval for exploration plans and development and production plans prior to the commencement of such operations. In addition to permits required from other agencies (such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency), lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities located on the Shelf to meet stringent engineering and construction specifications. The MMS also has regulations restricting the flaring or venting of natural gas, and prohibiting the burning of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the removal of all production facilities. To cover the various obligations of lessees on the Shelf, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of such bonds or other surety can be substantial and there is no assurance that bonds or other surety can be obtained in all cases. We are currently exempt from the supplemental bonding requirements of the MMS. Under certain circumstances, the MMS may require that our operations on federal leases be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations. The MMS regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases provide that the MMS will collect royalties based upon the market value of oil produced from federal leases. The 2005 EPA formalizes the royalty in-kind program of the MMS, providing that the MMS may take royalties in-kind if the Secretary of the Interior determines that the benefits are greater than or equal to the benefits that are likely to have been received had royalties been taken in value. We believe that the MMS royalty in-kind program will not have a material effect on our financial position, cash flows or results of operations.

State and Local Regulation of Drilling and Production. We own interests in properties located onshore Louisiana, Texas, New Mexico, Oklahoma and Utah. We also own interests in properties in the state waters offshore Texas and Louisiana. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilling and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells which may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states prorate production to the market demand for oil and gas.

Environmental Regulations. Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, or the issuance of injunctive relief. Environmental laws and regulations are complex, change frequently and have tended to become more stringent over time. Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted. Moreover, some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts onshore or offshore drilling or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and prospects could be adversely affected.

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

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

Table of Contents

$10 million for an oil spill in state waters and at least $35 million for an oil spill in federal waters. Since we currently have extensive operations in federal waters, we currently provide a total of $150 million in financial assurance to MMS.

In addition to OPA, our discharges to waters of the U.S. are further limited by the federal Clean Water Act, or CWA, and analogous state laws. The CWA prohibits any discharge into waters of the United States except in compliance with permits issued by federal and state governmental agencies. Failure to comply with the CWA, including discharge limits on permits issued pursuant to the CWA, may also result in administrative, civil or criminal enforcement actions. The OPA and CWA also require the preparation of oil spill response plans and spill prevention, control and countermeasure or SPCC plans. We have such plans in existence and are currently amending these plans or, as necessary, developing new SPCC plans that will satisfy new SPCC plan certification and implementation requirements that become effective in February 2006 and October 2007, respectively.

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

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

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

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

The Occupational Safety and Health Act (OSHA) and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees, state and local governmental authorities and the public.

International Regulations. Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above imposed by the respective governments

Table of Contents

of the countries in which we operate, and may affect our operations and costs within that country. We currently have operations in Malaysia, China and the United Kingdom.

Forward-Looking Information

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

- drilling results;
- oil and gas prices;
- well and waterflood performance;
- severe weather conditions (such as hurricanes);
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- the availability of capital resources; and
- the other factors affecting our business described above under the caption Risk Factors.

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

Commonly Used Oil and Gas Terms

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

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

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or condensate.

Bcf. Billion cubic feet.

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

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

Carried interest. An arrangement under which an interest in oil and gas rights is assigned in consideration for the assignee advancing all or a portion of the funds to explore on, develop or operate an oil or gas property.

Completion. The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Deep shelf. We consider the deep shelf to be structures located on the shelf at depths generally greater than 14,000 feet in over pressured horizons where there has been limited or no production from deeper stratigraphic zones. Prospects in this play are typically greater than 30 Bcfe and have dry hole costs of $15-30 million.

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

Developed acreage. The number of acres that are allocated or assignable to producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive.

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

Exploitation Well. An exploration well drilled to find and produce probable reserves. Most of the exploitation wells we drilled in 2005 and expect to drill in 2006 are located in the Mid-Continent or Monument Butte Field. Exploitation wells in those areas have less risk and less reserve potential and typically may be drilled at a lower cost than other exploration wells. For internal reporting and budgeting purposes, we combine exploitation and development activities.

Exploration or exploratory well. A well drilled to find and produce oil or natural gas reserves that is not a development well. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

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

FERC. The Federal Energy Regulatory Commission.

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

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

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

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

Mcf. One thousand cubic feet.

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

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

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

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or condensate.

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

NYMEX. The New York Mercantile Exchange.

Probable reserves. Reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery.

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

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

Proved developed reserves. In general, proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of proved developed reserves in Rule 4-10(a)(3) of Regulation S-X.

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

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

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

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

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

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

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

Workover. Operations on a producing well to restore or increase production.

Table of Contents

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

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

Oil and Gas Prices

We generally hedge a substantial, but varying, portion of our anticipated oil and gas production for the next 12-24 months as part of our risk management program. In the case of acquisitions, we may hedge acquired production for a longer period. 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. While hedging limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. For a further discussion of our hedging activities, see the information under the caption Oil and Gas Hedging in Item 7 of this report and Note 6, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements.

Interest Rates

At December 31, 2005, our long-term debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Bank revolving credit facility	$	$
7.45% Senior Notes due 2007[1]	75	50
75/8% Senior Notes due 2011[1]	125	50
83/8% Senior Subordinated Notes due 2012	250	
65/8% Senior Subordinated Notes due 2014	325	
Total long-term debt	$ 775	$ 100

(1) As of December 31, 2005, $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 75/8% Senior Notes due 2011 were subject to interest rate swaps. These swaps provide for us to pay variable and receive fixed interest payments, and are designated as fair value hedges of a portion of our outstanding senior notes.

We considered our interest rate exposure at year-end 2005 to be minimal because a substantial majority, about 89% of our long-term debt obligations, after taking into account our interest rate swap agreements, were at fixed rates. The impact on annual cash flow of a 10% change in the floating rate applicable to our variable rate debt would be less than $1 million.

Foreign Currency Exchange Rates

The British pound is the functional currency for our operations in the United Kingdom. The functional currency for all other foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country s functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at December 31, 2005.

Table of Contents

Item 8. *Financial Statements and Supplementary Data*

NEWFIELD EXPLORATION COMPANY

INDEX
CONSOLIDATED FINANCIAL STATEMENTS
AND SUPPLEMENTARY DATA

Table of Contents

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

Based on our evaluation under the framework in *Internal Control Integrated Framework,* the management of our company concluded that our internal control over financial reporting was effective as of December 31, 2005.

The assessment by the management of our company of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

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

Houston, Texas
March 1, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed integrated audits of Newfield Exploration Company s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005 and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of stockholders equity and of cash flows present fairly, in all material respects, the financial position of Newfield Exploration Company and its subsidiaries (the Company) at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations effective January 1, 2003 in conjunction with the Company s adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations.*

Internal control over financial reporting

Also, in our opinion, management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company;

Table of Contents

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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

Houston, Texas
March 2, 2006

Table of Contents

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEET
(In millions, except share data)

	December 31, 2005	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 39	$ 58
Accounts receivable	370	248
Inventories	22	8
Derivative assets	10	55
Deferred taxes	46	1
Other current assets	53	22
Total current assets	540	392
Oil and gas properties (full cost method, of which $901 and $835 were excluded from amortization at December 31, 2005 and December 31, 2004, respectively)	7,042	5,908
Less accumulated depreciation, depletion and amortization	(2,632)	(2,133)
	4,410	3,775
Furniture, fixtures and equipment, net	20	18
Derivative assets	17	56
Other assets	23	21
Deferred taxes	9	
Goodwill	62	65
Total assets	$ 5,081	$ 4,327
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 41	$ 32
Accrued liabilities	454	354
Advances from joint owners	29	18
Asset retirement obligation	47	23
Derivative liabilities	99	47
Total current liabilities	670	474
Other liabilities	21	16
Derivative liabilities	209	83
Long-term debt	870	992
Asset retirement obligation	213	194

Deferred taxes	720	551
Total long-term liabilities	2,033	1,836
Commitments and contingencies (Note 15)		
Stockholders equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)		
Common stock ($0.01 par value, 200,000,000 shares authorized at December 31, 2005 and 2004; 129,356,162 and 126,647,484 shares issued and outstanding at December 31, 2005 and 2004, respectively)	1	1
Additional paid-in capital	1,186	1,102
Treasury stock (at cost, 1,815,594 and 1,795,954 shares at December 31, 2005 and 2004, respectively)	(27)	(27)
Unearned compensation	(34)	(10)
Accumulated other comprehensive income (loss):		
Foreign currency translation adjustment	(4)	3
Commodity derivatives	(40)	
Retained earnings	1,296	948
Total stockholders equity	2,378	2,017
Total liabilities and stockholders equity	$ 5,081	$ 4,327

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

Table of Contents

NEWFIELD EXPLORATION COMPANY

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

	Year Ended December 31, 2005	2004	2003
Oil and gas revenues	$ 1,762	$ 1,353	$ 1,017
Operating expenses:			
Lease operating	205	152	125
Production and other taxes	64	42	32
Depreciation, depletion and amortization	521	472	395
Ceiling test writedown	10	17	
General and administrative	104	84	62
Other	(29)	35	20
Total operating expenses	875	802	634
Income from operations	887	551	383
Other income (expense):			
Interest expense	(72)	(58)	(58)
Capitalized interest	46	26	16
Dividends on convertible preferred securities of Newfield Financial Trust I			(5)
Commodity derivative expense	(322)	(24)	(6)
Other	4	4	2
	(344)	(52)	(51)
Income from continuing operations before income taxes	543	499	332
Income tax provision:			
Current	70	62	22
Deferred	125	125	99
	195	187	121
Income from continuing operations	348	312	211
Loss from discontinued operations, net of tax			(17)
Income before cumulative effect of change in accounting principle	348	312	194
Cumulative effect of change in accounting principle, net of tax:			
Adoption of SFAS No. 143			6
Net income	$ 348	$ 312	$ 200

Earnings per share:			
Basic			
Income from continuing operations	$ 2.78	$ 2.68	$ 1.94
Loss from discontinued operations			(0.16)
Cumulative effect of change in accounting principle, net of tax			0.05
Net income	$ 2.78	$ 2.68	$ 1.83
Diluted			
Income from continuing operations	$ 2.73	$ 2.63	$ 1.88
Loss from discontinued operations			(0.15)
Cumulative effect of change in accounting principle, net of tax			0.05
Net income	$ 2.73	$ 2.63	$ 1.78
Weighted average number of shares outstanding for basic earnings per share	125	117	109
Weighted average number of shares outstanding for diluted earnings per share	128	119	113

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

Table of Contents

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
(In millions)

	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount	Additional Paid-In Capital	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
Balance, December 31, 2002	105.2	$ 1	(1.8)	$ (26)	$ 636	$ (7)	$ 436	$ (31)	$ 1,009
Issuance of common stock	8.6				148				148
Issuance of restricted stock, less amortization and cancellations	0.4				7	(6)			1
Treasury stock, at cost				(1)					(1)
Amortization of stock compensation						2			2
Tax benefit from exercise of stock options					5				5
Comprehensive income:									
Net income							200		200
Foreign currency translation adjustment, net of tax of ($3)								5	5
Reclassification adjustments for settled hedging positions, net of tax of $26								(48)	(48)
Changes in fair value of outstanding hedging positions, net of tax of ($26)								49	49
Minimum pension liability, net of tax								(1)	(1)
Total comprehensive income									205
Balance, December 31, 2003	114.2	1	(1.8)	(27)	796	(11)	636	(26)	1,369
Issuance of common stock	12.2				297				297
Issuance of restricted stock, less amortization	0.2				3	(3)			

and cancellations									
Amortization of stock compensation						4			4
Tax benefit from exercise of stock options					6				6
Comprehensive income:									
Net income							312		312
Foreign currency translation adjustment, net of tax of ($1)								2	2
Reclassification adjustments for settled hedging positions, net of tax of $31								(57)	(57)
Changes in fair value of outstanding hedging positions, net of tax of ($45)								83	83
Minimum pension liability, net of tax								1	1
Total comprehensive income									341
Balance, December 31, 2004	126.6	1	(1.8)	(27)	1,102	(10)	948	3	2,017
Issuance of common stock	2.1				33				33
Issuance of restricted stock, less amortization and cancellations	0.7				34	(26)			8
Amortization of stock compensation						2			2
Tax benefit from exercise of stock options					17				17
Comprehensive income:									
Net income							348		348
Foreign currency translation adjustment, net of tax of $3								(7)	(7)
Reclassification adjustments for settled hedging positions, net of tax of $60								(110)	(110)
Reclassification adjustments for discontinued cash flow hedges, net of tax of $3								(7)	(7)
Changes in fair value of outstanding hedging positions, net of tax								77	77

of ($41)									
Total comprehensive income									301
Balance, December 31, 2005	129.4	$ 1	(1.8)	$ (27)	$ 1,186	$ (34)	$ 1,296	$ (44)	$ 2,378

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

53

Table of Contents

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)

	Year Ended December 31, 2005	2004	2003
Cash flows from operating activities:			
Net income	$ 348	$ 312	$ 200
Adjustments to reconcile net income to net cash provided by continuing operating activities:			
Loss from discontinued operations, net of tax			17
Depreciation, depletion and amortization	521	472	395
Deferred taxes	125	125	99
Stock compensation	10	4	3
Commodity derivative expense	210		6
Impairment (gain on sale) of floating production system and pipelines	(7)	35	
Gas sales obligation settlement and redemption of securities			20
Ceiling test writedown	10	17	
Cumulative effect of change in accounting principle			(6)
Changes in operating assets and liabilities:			
Increase in accounts receivable	(122)	(100)	(4)
(Increase) decrease in inventories	(15)	(5)	1
(Increase) decrease in other current assets	(14)	59	(34)
(Increase) decrease in other assets	2	(3)	4
Increase (decrease) in accounts payable and accrued liabilities	41	80	(23)
Decrease in commodity derivative liabilities	(14)	(11)	(14)
Increase in advances from joint owners	11	12	2
Increase (decrease) in other liabilities	3		(7)
Net cash provided by continuing activities	1,109	997	659
Net cash provided by discontinued activities			10
Net cash provided by operating activities	1,109	997	669
Cash flows from investing activities:			
Purchase of business, net of cash acquired of $2 and $1 for 2004 and 2003, respectively		(756)	(90)
Proceeds from sale of business			10
Proceeds from sale of oil and gas properties	11	17	
Additions to oil and gas properties	(1,047)	(853)	(531)
Additions to furniture, fixtures and equipment	(7)	(7)	(4)
Proceeds from sale of floating production system and pipelines	7		
Net cash used in continuing activities	(1,036)	(1,599)	(615)
Net cash used in discontinued activities			(3)

Net cash used in investing activities	(1,036)	(1,599)	(618)
Cash flows from financing activities:			
Proceeds from borrowings under credit arrangements	868	1,254	1,569
Repayments of borrowings under credit arrangements	(988)	(1,229)	(1,510)
Proceeds from issuance of common stock	32	297	149
Proceeds from issuance of senior subordinated notes		325	
Repayments of secured notes			(11)
Repurchases of secured notes		(3)	(63)
Gas sales obligation settlement			(62)
Deliveries under the gas sales obligation			(8)
Redemption of trust preferred securities			(149)
Net cash provided by (used in) continuing activities	(88)	644	(85)
Net cash provided by (used in) discontinued activities			
Net cash provided by (used in) financing activities	(88)	644	(85)
Effect of exchange rate changes on cash and cash equivalents	(4)	1	
Increase (decrease) in cash and cash equivalents	(19)	43	(34)
Cash and cash equivalents from continuing operations, beginning of period	58	15	34
Cash and cash equivalents from discontinued operations, beginning of period			15
Cash and cash equivalents, end of period	$ 39	$ 58	$ 15

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

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent oil and gas company engaged in the exploration, development and acquisition of crude oil and natural gas properties. Our company was founded in 1989 and initially focused on the shallow waters of the Gulf of Mexico. Today, we have a diversified asset base. 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 financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. We proportionately consolidate our interests in oil and gas exploration and production ventures and partnerships in accordance with industry practice. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to Newfield, we, us or our are to Newfield Exploration Company and its subsidiaries.

In September 2003, we sold Newfield Exploration Australia Ltd., the holding company for all of our Australian assets. As a result of the sale, the historical results of our Australian operations are reflected in our consolidated financial statements as discontinued operations. See Note 2, Discontinued Operations. Except where noted and for pro forma earnings per share, discussions in these notes relate to our continuing activities only.

Common Stock Split

Following the close of trading on May 25, 2005, we completed a two-for-one split of our common stock. The split was effected by a common stock dividend. As a result, the stated par value per share of our common stock was not changed from $0.01. These financial statements and notes have been restated to retroactively reflect the stock split.

Dependence on Oil and Gas Prices

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

Use of Estimates

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

Reclassifications

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

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Revenue Recognition

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

During the fourth quarter of 2005, we recognized a $22 million benefit related to our business interruption insurance coverage as a result of Hurricanes Katrina and Rita. This amount is recorded as a reduction of our operating expenses under the caption Other on our consolidated statement of income.

Allowance for Doubtful Accounts

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

We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. As of December 31, 2005 and 2004, our allowance for doubtful accounts was immaterial.

Inventories

Inventories consist primarily of tubular goods and well equipment held for use in our oil and gas operations and oil produced but not sold. Inventories are carried at the lower of cost or market. Crude oil from our operations offshore Malaysia is produced into a floating production, storage and off-loading vessel and sold periodically as a barge quantity is accumulated. The product inventory consisted of approximately 36,000 barrels and 49,000 barrels of crude oil at December 31, 2005 and 2004, respectively. Cost for purposes of the carrying value of oil inventory is a combination of production costs and depreciation, depletion and amortization expense.

Foreign Currency

The British pound is the functional currency for our operations in the United Kingdom. The functional currency for all other foreign operations is the U.S. dollar. Translation adjustments resulting from translating our United Kingdom subsidiaries British pound financial statements into U.S. dollars are included as accumulated other comprehensive income on our consolidated balance sheet and statement of stockholders equity. Gains and losses incurred on currency transactions in other than a country s functional currency are included on our consolidated statement of income.

Financial Instruments

We have included fair value information in these notes when the fair value of our financial instruments is materially different from their book value. Cash equivalents include highly liquid investments with a maturity of three months or less when acquired. We invested cash in excess of current capital and operating requirements in U.S. Treasury Notes, Eurodollar bonds and investment grade commercial paper. Cash equivalents are stated at cost, which approximates fair value.

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Oil and Gas Properties

We use the full cost method of accounting. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis. We capitalized $46 million, $32 million and $27 million of internal costs in 2005, 2004 and 2003, respectively. Interest expense related to unproved properties also is capitalized to oil and gas properties.

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

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

Proceeds from the sale of oil and gas properties are applied to reduce the costs in the applicable cost center unless the sale involves a significant quantity of reserves in relation to the cost center, in which case a gain or loss is recognized.

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

In November 2004, we announced that our Cumbria Prospect in the U.K. North Sea was a dry hole. Because the unamortized costs of our U.K. cost pool exceeded the full cost ceiling, we recognized a ceiling test writedown of $17 million in 2004.

Furniture, Fixtures and Equipment

Furniture, fixtures and equipment are recorded at cost and are depreciated using the straight-line method over their estimated useful lives, which range from three to seven years. At December 31, 2005 and 2004, furniture, fixtures and equipment of $39 million and $33 million, respectively, are net of accumulated depreciation of $19 million and $15 million, respectively.

Asset Retirement Obligations

We adopted Financial Accounting Standards Board (FASB) Statement (SFAS) No. 143, Accounting for Asset Retirement Obligations, as of January 1, 2003. This statement changed the method of accounting for expected future costs associated with our obligations to perform site reclamation, dismantle facilities and plug and abandon wells. If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, we record a liability (an asset retirement obligation or ARO) on our consolidated balance sheet and capitalize the asset retirement cost in oil and gas properties in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

for our company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis within the related full cost pool. Both the accretion and the depreciation are included in depreciation, depletion and amortization on our consolidated statement of income.

Prior to January 1, 2003, we recognized the undiscounted estimated cost to abandon our oil and gas properties over their estimated productive lives on a unit-of-production basis as a component of depreciation, depletion and amortization expense and no liabilities or capitalized costs associated with such abandonment were recorded on our consolidated balance sheet. At adoption of SFAS No. 143, a cumulative effect of change in accounting principle was required in order to recognize:

- an initial ARO as a liability on our consolidated balance sheet;
- an increase in oil and gas properties for the cost to abandon our oil and gas properties;
- cumulative accretion of the ARO from the period incurred up to the January 1, 2003 adoption date; and
- cumulative depreciation on the additional capitalized costs included in oil and gas properties up to the January 1, 2003 adoption date.

As a result of our adoption of SFAS No. 143, we recorded a $135 million increase in the net capitalized costs of our oil and gas properties and an initial ARO of $129 million. Additionally, we recognized an after-tax gain of $6 million (the after-tax amount by which additional capitalized costs, net of accumulated depreciation, exceeded the initial ARO, including in each case discontinued operations) as the cumulative effect of change in accounting principle.

The change in our ARO since adoption of SFAS No. 143 is set forth below (in millions):

Balance at January 1, 2003	$ 129
Accretion expense	7
Additions	32
Settlements	(4)
Balance at December 31, 2003	164
Accretion expense	11
Additions	48
Settlements	(6)
Balance at December 31, 2004	217
Accretion expense	13
Additions	10
Revisions[(1)]	34
Settlements	(14)

Balance at December 31, 2005	$ 260

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

Goodwill

We recorded goodwill in connection with our acquisitions of Inland Resources (August 2004) and Primary Natural Resources (September 2003). Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of the liabilities assumed. In the third quarter

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of 2005, the goodwill associated with Inland Resources was adjusted to reflect the recognition of an additional $3 million in tax assets.

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

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

We have not impaired any goodwill.

Income Taxes

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

Stock-Based Compensation

We account for our employee stock options using the intrinsic value method prescribed by Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees (APB 25).

If the fair value based method of accounting under SFAS No. 123, Accounting for Stock-Based Compensation, had been applied using a Black-Scholes option pricing model, our net income and earnings per common share for 2005, 2004 and 2003 would have approximated the pro forma amounts below:

	Year Ended December 31,		
	2005	2004	2003
	(In millions, except per share data)		
Net income:			
As reported[1]	$ 348	$ 312	$ 200

Pro forma[2]	339	305	193
Basic earnings per common share			
As reported	$ 2.78	$ 2.68	$ 1.83
Pro forma	2.70	2.61	1.78
Diluted earnings per common share			
As reported	$ 2.73	$ 2.63	$ 1.78
Pro forma	2.65	2.57	1.73

(1) Includes stock-based compensation costs, net of related tax effects, of $7 million, $3 million and $2 million for the years ended December 31, 2005, 2004 and 2003, respectively.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Includes stock-based compensation costs, net of related tax effects, that would have been included in the determination of net income had the fair value based method been applied of $16 million, $10 million and $9 million for the years ended December 31, 2005, 2004 and 2003, respectively.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), Share Based Payment, (SFAS No. 123(R)). SFAS No. 123(R) is a revision of SFAS No. 123, Accounting for Stock Based Compensation, and supercedes ABP 25. Among other items, SFAS No. 123(R) eliminates the use of APB 25 and the intrinsic value method of accounting and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. SFAS No. 123(R) permits companies to adopt its requirements using either a modified prospective method, a variation of the modified prospective method or a modified retrospective method. We intend to use the modified prospective transition method when we adopt the standard effective as of January 1, 2006. Under this method, compensation cost will be recognized in our financial statements beginning on the adoption date, based on the requirements of SFAS No. 123(R) for all share-based payments granted or modified after that date, and based on the requirements of SFAS No. 123 for all unvested awards granted prior to the adoption date of SFAS No. 123(R).

We expect to continue to utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted and to utilize a lattice based model for our performance based restricted stock grants.

SFAS No. 123(R) also requires that the benefits associated with tax deductions in excess of recognized compensation cost be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce reported net operating cash flows and increase reported net financing cash flows in periods after the effective date. These future amounts cannot be estimated because they depend on, among other things, when employees exercise stock options.

We currently expect the adoption of SFAS No. 123(R) will impact our results of operations, but will not impact our overall financial position. The impact of the adoption of SFAS No. 123(R) on our reported results of operations for future periods will depend on the level of share-based payments granted in the future. However, had we adopted SFAS No. 123(R) in prior periods, the impact of that standard would have approximated the impact of SFAS No. 123 as described in the table above.

Concentration of Credit Risk

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

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

All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions involves the risk that the counterparties may be unable to meet the financial terms of the transactions. The counterparties for all of our hedging transactions have an investment grade credit rating. We monitor on an ongoing basis the credit ratings of our hedging counterparties. At December 31, 2005, Bank

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of Montreal, JPMorgan Chase Bank, Barclays Bank PLC and J Aron & Company were the counterparties with respect to 77% of our future hedged production.

Major Customers

For the years ended December 31, 2003, 2004 and 2005, we sold oil and gas production that accounted for more than 10% of our consolidated revenues (before the effects of hedging) to Superior Natural Gas Corporation (23% in 2005, 20% in 2004 and 29% in 2003), Louis Dreyfus Energy Services (12% in 2005, 15% in 2004 and less than 10% in 2003) and ConocoPhillips Inc. (less than 10% in 2005, 14% in 2004 and 25% in 2003). Because alternative purchasers of oil and gas are readily available in most geographic areas, we believe that the loss of any of these purchasers would not have a material adverse effect on us.

Derivative Financial Instruments

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

Historically we have applied hedge accounting to derivatives utilized to manage price risk associated with our oil and gas production. Accordingly, we have recorded changes in the fair value of our collar and floor contracts (other than contracts that are part of three-way collar contracts), including changes associated with time value, under the caption Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet. Gains or losses on these collar and floor contracts are reclassified out of Accumulated other comprehensive income (loss) Commodity derivatives and into oil and gas revenues when the forecasted sale of production occurs.

Any hedge ineffectiveness associated with contracts qualifying for and designated as a cash flow hedge (which represents the amount by which the change in the fair value of the derivative differs from the change in the cash flows of the forecasted sale of production) is reported currently each period under the caption Commodity derivative expense on our consolidated statement of income.

Some of our derivatives (three-way collar contracts) do not qualify for hedge accounting but are effective as economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Derivative assets and Derivative liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of income under the caption Commodity derivative expense.

Beginning with the fourth quarter of 2005, we elected not to designate any future price risk management activities as accounting hedges under SFAS No. 133, and accordingly, will account for them using the mark-to-market accounting method described above. Previously designated and qualifying derivatives will continue to be accounted for as cash flow hedges.

The related cash flow impact of all of our derivative activities are reflected as cash flows from operating activities. See Note 6, Commodity Derivative Instruments and Hedging Activities, for a full discussion of our hedging activities.

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Comprehensive Income (Loss)

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

New Accounting Standards

In December 2004, the FASB issued SFAS No. 123(R). See *Stock-Based Compensation* above.

2. Discontinued Operations:

In September 2003, we sold our wholly owned subsidiary, Newfield Exploration Australia Ltd., the holding company for all of our Australian assets. The historical results of our Australian operations are reflected in our consolidated financial statements as discontinued operations and are summarized as follows:

	For the Year Ended December 31, 2003 (In millions)
Revenues	$ 16
Operating expenses[1]	(22)
Loss from operations	(6)
Other expense[2]	(4)
Loss before income taxes	(10)
Income tax benefit	3
Loss from operations	(7)
Loss on sale	(10)
Loss from discontinued operations	$ (17)

(1) Operating expenses for the year ended December 31, 2003 include a ceiling test writedown of $7 million and a production tax credit due to a change in the estimate of Australian resource rent taxes recorded in the second quarter of 2003.

(2) Other expense primarily consists of foreign currency exchange gains and losses.

3. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted average number of shares of common stock (other than unvested restricted stock) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options (using the treasury stock method), unvested restricted stock and the assumed conversion of our trust preferred securities as if exercise or conversion to common stock had occurred at the beginning of the accounting period. Net income also has been increased for any accrued distributions with respect to our trust preferred securities accrued during any of the periods presented. We redeemed all of our outstanding trust preferred securities in June 2003. See Note 9, Redemption of Trust Preferred Securities and Note 12, Stock-Based Compensation *Stock Options.*

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following is the calculation of basic and diluted weighted average shares outstanding and EPS for each of the years in the three-year period ended December 31, 2005:

	2005	2004	2003
	(In millions, except per share data)		
Income (numerator):			
Income from continuing operations	$ 348	$ 312	$ 211
Loss from discontinued operations, net of tax			(17)
Income before cumulative effect of change in accounting principle	348	312	194
Cumulative effect of change in accounting principle, net of tax			6
Net income basic	348	312	200
After-tax dividends on convertible trust preferred securities			3
Net income diluted	$ 348	$ 312	$ 203
Weighted average shares (denominator):			
Weighted average shares basic	125	117	109
Dilution effect of stock options and unvested restricted stock outstanding at end of period	3	2	1
Dilution effect of convertible trust preferred securities			3
Weighted average shares diluted	128	119	113
Earnings per share:			
Basic:			
Income from continuing operations	$ 2.78	$ 2.68	$ 1.94
Loss from discontinued operations			(0.16)
Cumulative effect of change in accounting principle, net of tax			0.05
Net income	$ 2.78	$ 2.68	$ 1.83
Diluted:			
Income from continuing operations	$ 2.73	$ 2.63	$ 1.88
Loss from discontinued operations			(0.15)
Cumulative effect of change in accounting principle, net of tax			0.05
Net income	$ 2.73	$ 2.63	$ 1.78

The calculation of shares outstanding for diluted EPS for the years ended December 31, 2005, 2004 and 2003 does not include the effect of outstanding stock options to purchase 69 thousand, 728 thousand and 1,368 thousand shares, respectively, because to do so would be antidilutive.

4. Acquisitions:

Malaysian PSCs

Over the past two years, we have entered into several production sharing contracts, or PSCs, with Malaysia s state-owned oil company relating to blocks offshore Malaysia. In June 2005, we entered into a PSC with respect to PM 323. We operate the block with a 60% interest. The PSC covers approximately 320,000 acres in the Malay Basin and is located approximately 40 miles from PM 318. The consideration for

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

our interest was comprised of a deferred payment of $8 million and a future development and exploration commitment.

In May 2004, we entered into several PSCs that relate to two blocks PM 318 and deepwater Block 2C. Petronas Carigali, a state-owned, Malaysian exploration and production company, operates PM 318, which consists of approximately 414,000 acres, located offshore Peninsular Malaysia. We have a 50% interest in the block. The consideration for our interests in PM 318 was comprised of a one-time reimbursement of sunk costs of $39 million and a deferred payment of $11 million. Block 2C covers 1.1 million acres in deepwater offshore Sarawak and is operated by us with a 60% interest. We have committed to future exploration on these two blocks.

See Note 15, Commitments and Contingencies *Other Commitments*.

Oklahoma Assets

During the second half of 2004, we acquired producing oil and gas properties in Oklahoma in two separate transactions for total cash consideration of approximately $58 million. These acquisitions were financed through cash on hand and borrowings under our credit arrangements.

Denbury Offshore, Inc.

On July 20, 2004, we acquired all of the outstanding stock of Denbury Offshore, Inc., the subsidiary of Denbury Resources Inc. that held substantially all of its Gulf of Mexico assets. We accounted for the acquisition as a purchase using the accounting standards established in SFAS No. 141, Business Combinations. Our consolidated financial statements include Denbury Offshore s results of operations subsequent to July 20, 2004. After purchase price adjustments, total consideration was approximately $174 million, substantially all of which was allocated to oil and gas properties. The acquisition was financed through cash on hand and borrowings under our credit arrangements.

Inland Resources Inc.

On August 27, 2004, we completed the $575 million acquisition of privately held Inland Resources Inc. Inland s sole oil and gas property was the 100,000 acre Monument Butte Field, located in the Uinta Basin of northeast Utah. The purchase price was funded through concurrent offerings of our common stock and our 65/8% Senior Subordinated Notes due 2014. See Note 8, Debt, and Note 10, Common Stock Activity.

We accounted for the acquisition as a purchase using the accounting standards established in SFAS Nos. 141 and 142. Our consolidated financial statements include Inland s results of operations subsequent to August 27, 2004. We recorded the estimated fair value of the assets acquired and the liabilities assumed at August 27, 2004, which primarily consisted of oil and gas properties of $723 million, a deferred tax liability of $171 million, derivative liabilities of $31 million and goodwill of $49 million. We recorded the deferred tax liability to recognize the difference between the historical tax basis of Inland s net assets and the acquisition costs recorded for accounting purposes. Inland s historical book value of the proved and unproved oil and gas properties was increased to estimated fair value and goodwill was recorded to recognize this tax basis differential. In the third quarter of 2005, goodwill was reduced to reflect the recognition of an additional $3 million tax asset related to the acquisition. Goodwill is not deductible for tax purposes. See Note 1, Organization and Summary of Significant Accounting Policies *Goodwill.*

Pro Forma Results

The unaudited pro forma results presented below for the years ended December 31, 2004 and 2003 have been prepared to give effect to our 2004 acquisitions and the issuance of our common stock and notes (See Note 8, Debt *Senior Subordinated Notes* and Note 10, *Common Stock Activity*) on our results of

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

operations under the purchase method of accounting as if they had been consummated on January 1, 2003. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if these acquisitions had in fact occurred on such date or to project our results of operations for any future date or period.

	Year Ended December 31, 2004	2003
	(Unaudited) (In millions, except per share)	
Pro forma:		
Revenue	$ 1,457	$ 1,147
Income from operations	589	409
Net income	344	223
Basic earnings per share	$ 2.79	$ 1.87
Diluted earnings per share	$ 2.75	$ 1.87

5. Oil and Gas Assets:

Oil and Gas Properties

Oil and gas properties consisted of the following at:

	December 31, 2005	December 31, 2004 (In millions)	December 31, 2003
Subject to amortization	$ 6,141	$ 5,073	$ 3,747
Not subject to amortization			
Exploration in progress	147	91	39
Development in progress	16	7	
Capitalized interest	71	39	23
Fee mineral interests	23	23	23
Other capital costs:			
Incurred in 2005	110		
Incurred in 2004	413	479	
Incurred in 2003	51	77	102
Incurred in 2002 and prior	70	119	144
Total not subject to amortization	901	835	331
Gross oil and gas properties	7,042	5,908	4,078

Accumulated depreciation, depletion and amortization		(2,632)		(2,133)		(1,660)
Net oil and gas properties	$	4,410	$	3,775	$	2,418

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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2005 and 2004, we excluded from the amortization base $26 million (which is included in costs not subject to amortization in the table above) associated with our deepwater Gulf of Mexico project known as Glider, located at Green Canyon 247/248.

We believe that substantially all of the properties associated with costs not currently subject to amortization will be evaluated within four years except the Monument Butte Field, which was the sole oil and gas property of Inland Resources. Because of its size, evaluation of the Monument Butte Field in its entirety will take significantly longer than four years. At December 31, 2005 and 2004, $316 million and $341 million, respectively, of costs associated with the Monument Butte Field were not subject to amortization.

Floating Production System and Pipelines

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.

From their acquisition, we undertook 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 under the caption Other on our consolidated statement of income 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 under the caption Other on our consolidated statement of income.

6. Commodity Derivative Instruments and Hedging Activities:

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

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract. For a floor contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are not required to make any payment in connection with the settlement of a floor contract. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract, we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. A three-way collar contract consists of a standard collar contract plus a put sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in us being entitled to a net payment equal to the difference between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. This strategy enables us to increase the

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

floor and the ceiling price of the collar beyond the range of a traditional no cost collar while defraying the associated cost with the sale of the additional put.

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

Cash Flow Hedges

Prior to the fourth quarter of 2005, all derivatives that qualified for hedge accounting were designated on the date we entered into the contract as a hedge of the variability in cash flows associated with the forecasted sale of our future oil and gas production. After-tax changes in the fair value of a derivative that is highly effective and is designated and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet until the sale of the hedged oil and gas production. Upon the sale of the hedged production, the net after-tax change in the fair value of the associated derivative recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives is reversed and the gain or loss on the hedge, to the extent that it is effective, is reported in Oil and gas revenues on our consolidated statement of income. At December 31, 2005, we had a net $40 million after-tax loss recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives. We expect hedged production associated with commodity derivatives accounting for a net loss of approximately $49 million to be sold within the next 12 months and hedged production associated with a remaining net gain of approximately $9 million to be sold thereafter. The actual gain or loss on these commodity derivatives could vary significantly as a result of changes in market conditions and other factors.

For those contracts designated as a cash flow hedge, we formally document all relationships between the derivative instruments and the hedged production, as well as our risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or gas at its physical location. We also formally assess (both at the derivative s inception and on an ongoing basis) whether the derivatives being utilized have been highly effective at offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, we will discontinue hedge accounting prospectively. If hedge accounting is discontinued and the derivative remains outstanding, we will carry the derivative at its fair value on our consolidated balance sheet and recognize all subsequent changes in its fair value on our consolidated statement of income for the period in which the change occurs. As a result of 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 fourth quarter of 2005 natural gas and crude oil cash flow hedges. Other natural gas and crude oil contracts were redesignated as hedges of our onshore Gulf Coast production. As a result of the discontinuance of hedge accounting, unrealized hedging losses of $11 million previously deferred to Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet were recorded as commodity derivative expense in 2005. Additionally, 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 that period, were reported as commodity derivative expense.

Other Derivative Contracts

Although our three-way collar contracts are effective as economic hedges of our commodity price exposure, they do not qualify for hedge accounting under SFAS No. 133. Beginning in the fourth quarter of

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2005 we elected not to designate any additional derivative contracts as accounting hedges under SFAS No. 133. Our three-way collar contracts as well as the other derivative contracts that are not designated as cash flow hedges are carried at their fair value on our consolidated balance sheet under the captions Derivative assets and Derivative liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of income under the caption Commodity derivative expense. We recognized realized losses on these contracts of $61 million and $24 million in 2005 and 2004, respectively. There were no contracts that did not quality for hedge accounting that settled in 2003.

Natural Gas

At December 31, 2005, we had entered into derivative contracts that qualify as cash flow hedges with respect to our future natural gas production as follows:

		NYMEX Contract Price Per MMBtu							Estimat
			Collars						Fair Value
		Swaps	Floors		Ceilings		Floor Contracts		Asset
	Volume in	(Weighted		Weighted		Weighted		Weighted	(Liabilit (In
eriod and Type of Contract	MMMBtus	Average)	Range	Average	Range	Average	Range	Average	million
nuary 2006 - March 2006									
ice swap contracts	7,200	$8.96							$(17
ollar contracts	2,400		$5.80	$5.80	$10.00	$10.00			(4
oor contracts	5,100						$7.50 - $7.65	$7.55	
pril 2006 - June 2006									
oor contracts	4,800						7.35	7.35	
ly 2006 - September 2006									
oor contracts	4,800						7.35	7.35	1
ctober 2006 - December 2006									
oor contracts	1,600						7.35	7.35	
									$(20

At December 31, 2005, we also had entered into other contracts with respect to our future natural gas production as set forth in the table below. These contracts do not qualify for or have not been designated as a cash flow hedge for hedge accounting.

NYMEX Contract Price Per MMBtu

Collars

		Swaps	Additional Put		Floors		Ceilings		
	Volume in	(Weighted		Weighted		Weighted		Weighted	
ontract	MMBtus	Average)	Range	Average	Range	Average	Range	Average	Rang
2006									
	11,850		$4.50 - $8.50	$6.47	$6.00 - $10.00	$7.61	$10.00 - $14.50	$12.13	
	3,060	$10.25							
	2,040				9.00 - 9.35	9.26	13.80 - 20.00	15.50	
	510								$8.2
2006									
	3,060	10.25							
	2,040				9.00 - 9.35	9.26	13.80 - 20.00	15.50	
	510								8.2

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Oil

At December 31, 2005, we had entered into derivative contracts that qualify as cash flow hedges with respect to our future oil production as follows:

		NYMEX Contract Price Per Bbl					Estimated Fair Value Asset
			Collars				
		Swaps	Floors		Ceilings		
Period and Type of Contract	**Volume in Bbls**	**(Weighted Average)**	**Range**	**Weighted Average**	**Range**	**Weighted Average**	**(Liability) (In millions)**
January 2006 - March 2006							
Price swap contracts	741	$ 46.71					$ (11)
Collar contracts	150		$ 50.00 - $55.00	$ 52.50	$ 73.90 - $83.75	$ 78.81	
April 2006 - June 2006							
Price swap contracts	747	46.77					(12)
Collar contracts	151		50.00 - 55.00	52.51	73.90 - 83.75	78.83	
July 2006 - September 2006							
Price swap contracts	753	46.83					(12)
Collar contracts	151		50.00 - 55.00	52.52	73.90 - 83.75	78.84	
October 2006 - December 2006							
Price swap contracts	753	46.83					(13)
Collar contracts	151		50.00 - 55.00	52.52	73.90 - 83.75	78.84	
January 2007 - December 2007							
Price swap contracts	605	47.66					(9)
Collar contracts	365		50.00 - 55.00	52.50	77.10 - 83.25	80.18	
							$ (57)

At December 31, 2005, we also had entered into other contracts with respect to our future oil production as set forth in the table below. These contracts do not qualify for hedge accounting.

	NYMEX Contract Price Per Bbl						Es
			Collars				
	Additional Put		Floors		Ceilings		
Volume in		**Weighted**		**Weighted**		**Weighted**	**(L**

and Type of Contract	Bbls	Range	Average	Range	Average	Range	Average	m
2006 - March 2006								
collar contracts	414	$ 30.00 - $50.00	$ 38.51	$ 35.00 - $60.00	$ 45.96	$ 50.50 - $80.00	$ 63.31	S
006 - June 2006								
collar contracts	417	30.00 - 50.00	38.50	35.00 - 60.00	45.95	50.50 - 80.00	63.27	
06 - September 2006								
collar contracts	480	30.00 - 50.00	37.43	35.00 - 60.00	44.69	50.50 - 80.00	62.21	
r 2006 - December 2006								
collar contracts	480	30.00 - 50.00	37.43	35.00 - 60.00	44.69	50.50 - 80.00	62.21	
2007 - December 2007								
collar contracts	3,525	25.00 - 50.00	30.02	32.00 - 60.00	37.12	44.70 - 82.00	55.32	
2008 - December 2008								
collar contracts	3,294	25.00 - 29.00	26.56	32.00 - 35.00	33.00	49.50 - 52.90	50.29	
2009 - December 2009								
collar contracts	3,285	25.00 - 30.00	27.00	32.00 - 36.00	33.33	50.00 - 54.55	50.62	
2010 - December 2010								
collar contracts	3,645	25.00 - 32.00	28.60	32.00 - 38.00	34.90	50.00 - 53.50	51.52	
								S

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Accrued Liabilities:

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

	December 31, 2005	December 31, 2004
	(In millions)	
Revenue payable	$ 117	$ 109
Accrued capital costs	154	101
Accrued lease operating expenses	33	26
Employee incentive expense	60	45
Accrued interest on notes	21	22
Taxes payable	26	14
Deferred acquisition payments	20	17
Other	23	20
Total accrued liabilities	$ 454	$ 354

8. Debt:

As of the indicated dates, our long-term debt consisted of the following:

	December 31, 2005	December 31, 2004
	(In millions)	
Senior unsecured debt:		
Bank revolving credit facility:		
Prime rate based loans	$	$
LIBOR based loans(1)		120
Total bank revolving credit facility		120
7.45% Senior Notes due 2007	125	125
Fair value of interest rate swaps(2)	(2)	(1)
75/8% Senior Notes due 2011	175	175
Fair value of interest rate swaps(2)	(2)	
Total senior unsecured notes	296	299

Total senior unsecured debt		296		419
83/8% Senior Subordinated Notes due 2012		249		248
65/8% Senior Subordinated Notes due 2014		325		325
Total long-term debt	$	870	$	992

(1) At December 31, 2004, the interest rate was 3.63% for LIBOR based loans.

(2) See *Interest Rate Swaps* below.

Credit Arrangements

In December 2005, we entered into a revolving credit facility that matures in December 2010. The terms of the credit facility provide for initial loan commitments of $1 billion from a syndication of participating banks, led by JPMorgan Chase as the agent bank. The loan commitments under the credit facility may be

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

increased to a maximum aggregate amount of $1.5 billion if the lenders increase their loan commitments or new financial institutions are added to the credit facility. Loans under the credit facility bear interest, at the option of the Company, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate, substantially equal to the London Interbank Offered Rate (LIBOR), plus a margin that is based on a grid of our debt rating (100 basis points per annum at December 31, 2005). At December 31, 2005, we had no borrowings under the credit facility.

Under our new credit facility and our previous credit facilities, we pay or paid commitment fees on the undrawn amounts based on a grid of our debt rating (.20% per annum at December 31, 2005). We paid fees under these arrangements of approximately $2 million, $1 million and $1 million for the years ended December 31, 2005, 2004 and 2003, respectively.

The credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed .60 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 calculated net present value of our oil and gas properties to total debt of at least 1.75 to 1.00. At December 31, 2005, we were in compliance with all of its debt covenants.

As of December 31, 2005, we had $50 million of undrawn letters of credit under our credit facility. The letters of credit outstanding under the credit facility are subject to annual fees, based on a grid of our debt rating (87.5 basis points at December 31, 2005), plus an issuance fee of 12.5 basis points.

We also have a total of $110 million of borrowing capacity under money market lines of credit with various banks. At December 31, 2005, we had no borrowings under our money market lines.

Senior Notes

On February 22, 2001, we issued $175 million aggregate principal amount of our 75/8% Senior Notes due 2011. The estimated fair value of these notes at December 31, 2005 and 2004 was $188 million and $196 million, respectively, based on quoted market prices on those dates.

On October 15, 1997, we issued $125 million aggregate principal amount of our 7.45% Senior Notes due 2007. The estimated fair value of these notes at December 31, 2005 and 2004 was $128 million and $135 million, respectively, based on quoted market prices on those dates.

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 may 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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Senior Subordinated Notes

On August 12, 2004, we issued $325 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2014. The net proceeds of $323 million were used together with the net proceeds of our concurrent stock offering (see Note 10, Common Stock Activity) to fund the acquisition of Inland (see Note 4, Acquisitions). The estimated fair value of these notes at December 31, 2005 and 2004 was $332 million and $343 million, respectively, based on quoted market prices on those dates.

On August 13, 2002, we issued $250 million aggregate principal amount of our 83/8% Senior Subordinated Notes due 2012. The net proceeds from the offering (approximately $242 million) were used to repay debt of EEX Corporation that became due at the closing of our acquisition of EEX and to pay related transaction costs. The estimated fair value of these notes at December 31, 2005 and 2004 was $268 million and $279 million, respectively, based on quoted market prices on those dates.

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

We may redeem some or all of the 83/8% notes at any time on or after August 15, 2007 and some or all of the 65/8% notes at any time on or after September 1, 2009, in each case, at a redemption price stated in the applicable supplemental indenture governing the notes. We also may redeem all but not part of the 83/8% notes prior to August 15, 2007 and all but not part of the 65/8% notes prior to September 1, 2009, 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 the 65/8% notes 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.

Secured Notes

In connection with our acquisition of EEX Corporation in November 2002, we assumed $101 million principal amount of secured notes. The notes accrued interest at a rate of 7.54% per year and were secured by the floating production system and pipelines described in Note 5, Oil and Gas Assets *Floating Production System and Pipelines*. Principal was payable in annual installments on January 2 of each year (except 2006) with the final installment due in 2009. We repurchased $24 million principal amount of secured notes in December 2002. In addition to the scheduled payment of $11 million of principal we made during 2003, we also repurchased $63 million outstanding principal amount of secured notes. In January 2004, we repurchased the remaining $3 million of secured notes.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Interest Rate Swaps

During September 2003, we entered into interest rate swap agreements to take advantage of low interest rates and to obtain what we viewed as a more desirable proportion of variable and fixed rate debt. We hedged $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 75/8% Senior Notes due 2011. These swap agreements provide for us to pay variable and receive fixed interest payments and are designated as fair value hedges of a portion of our outstanding senior notes.

Pursuant to SFAS No. 133, changes in the fair value of derivatives designated as fair value hedges are recognized as offsets to the changes in fair value of the exposure being hedged. As a result, the fair value of our interest rate swap agreements is reflected within our derivative assets or liabilities on our consolidated balance sheet and changes in their fair value are recorded as an adjustment to the carrying value of the associated long-term debt. Receipts and payments related to our interest rate swaps are reflected in interest expense.

Gas Sales Obligation Settlement

Pursuant to a gas forward sales contract entered into in 1999, EEX committed to deliver approximately 50 Bcf of production to a third party in exchange for proceeds of $105 million. When we acquired EEX in November 2002, we recorded a liability of $62 million, which represented the then current market value of approximately 16 Bcf of remaining reserves subject to the contract. We accounted for the obligation under the gas sales contract as debt on our consolidated balance sheet. In March 2003, pursuant to a settlement agreement the gas sales contract and all related agreements were terminated in exchange for a payment by us of approximately $73 million. We recognized a loss of $10 million under the caption Other on our consolidated statement of income as a result of the settlement.

9. Redemption of Trust Preferred Securities:

In June 2003, we redeemed all of our outstanding convertible trust preferred securities for an aggregate redemption price of approximately $148 million, including $6 million of optional redemption premium. This premium and $4 million of unamortized offering costs (which were being amortized over the 30-year life of the securities) were expensed under the caption Other on our consolidated statement of income. We financed the redemption with the net proceeds (approximately $131 million) from the issuance and sale of 3.5 million shares of our common stock in May 2003 and borrowings under our credit arrangements.

10. Common Stock Activity:

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

In May 2004, we amended our Second Restated Certificate of Incorporation to increase the authorized number of shares of our common stock that we have authority to issue from 100,000,000 to 200,000,000.

On August 12, 2004, we issued 5.4 million shares (10.8 million post split) of our common stock at $52.85 per share ($26.43 post split). The net proceeds of $277 million were used in conjunction with the net proceeds of our concurrent Senior Subordinated Notes offering (see Note 8, Debt *Senior Subordinated Notes*) to acquire Inland (see Note 4, Acquisitions *Inland Resources Inc.*).

Also see Note 9, Redemption of Trust Preferred Securities.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Income Taxes:

Income from continuing operations before income taxes consists of the following:

	For the Year Ended December 31,		
	2005	2004	2003
	(In millions)		
U.S.	$ 515	$ 496	$ 333
Foreign	28	3	(1)
Total	$ 543	$ 499	$ 332

The total provision (benefit) for income taxes consists of the following:

	For the Year Ended December 31,		
	2005	2004	2003
	(In millions)		
Current taxes:			
U.S. federal	$ 54	$ 53	$ 21
U.S. state	1	1	1
Foreign	15	8	
Deferred taxes:			
U.S. federal	121	118	95
U.S. state	11	7	4
Foreign	(7)		
Total provision for income taxes	$ 195	$ 187	$ 121

The provision for income taxes for each of the years in the three-year period ended December 31, 2005 was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	For the Year Ended December 31,		
	2005	2004	2003
	(In millions)		

Amount computed using the statutory rate	$ 190	$ 175	$ 116
Increase (decrease) in taxes resulting from:			
State and local income taxes, net of federal effect	8	5	2
Federal statutory rate in excess of foreign rate	1	(1)	
Tax credits and other	1		3
Valuation allowance	(5)	8	
Total provision for income taxes	$ 195	$ 187	$ 121

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of our deferred tax asset and deferred tax liability are as follows:

	December 31, 2005			December 31, 2004		
	U.S.	Foreign	Total	U.S.	Foreign	Total
	(In millions)					
Deferred tax asset:						
Net operating loss carryforwards	$ 112	$ 14	$ 126	$ 128	$ 11	$ 139
Commodity derivatives	31		31	1		1
Other, net	9		9	24		24
Valuation allowance		(3)	(3)		(8)	(8)
Deferred tax asset	152	11	163	153	3	156
Deferred tax liability:						
Oil and gas properties	(826)	(2)	(828)	(706)		(706)
Net deferred tax asset (liability)	(674)	9	(665)	(553)	3	(550)
Less net current deferred tax asset (liability)	46		46	1		1
Noncurrent deferred tax asset (liability)	$ (720)	$ 9	$ (711)	$ (554)	$ 3	$ (551)

As of December 31, 2005, we had net operating loss (NOL) carryforwards for federal income tax purposes of approximately $295 million that may be used in future years to offset taxable income. Utilization of the NOL carryforwards is subject to annual limitations due to certain stock ownership changes. To the extent not utilized, the NOL carryforwards will begin to expire during the years 2019 through 2024. Utilization of NOL carryforwards is dependent upon generating sufficient taxable income in the appropriate jurisdictions within the carryforward period. Estimates of future taxable income can be significantly affected by changes in natural gas and oil prices, estimates of the timing and amount of future production and estimates of future operating and capital costs.

The $8 million deferred tax asset valuation allowance at December 31, 2004 was related to a U.K. NOL carryforward that was recorded in 2004. This valuation allowance was reversed in 2005 as a result of a substantial increase in estimated future taxable income as a result of our Grove discovery in the U.K. North Sea. In 2005, we recorded a valuation allowance of $3 million for Brazilian and various other international deferred tax assets related to NOL carryforwards.

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

12. Stock-Based Compensation:

We have several stock-based compensation plans, which are described below. We apply the intrinsic value method prescribed by APB 25 and related interpretations in accounting for our stock-based compensation plans. See Note 1, Organization and Summary of Significant Accounting Policies *Stock-Based Compensation*.

Stock Options

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

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following is a summary of all stock option activity for 2003, 2004 and 2005:

	Number of Shares Underlying Options	Weighted Average Exercise Price
Outstanding at December 31, 2002	7,747	$ 14.24
Granted	1,264	17.79
Exercised	(1,557)	9.64
Forfeited	(832)	17.70
Outstanding at December 31, 2003	6,622	15.57
Granted	2,034	26.19
Exercised	(1,378)	13.63
Forfeited	(273)	20.77
Outstanding at December 31, 2004	7,005	18.83
Granted	1,883	33.23
Exercised	(1,989)	15.74
Forfeited	(426)	24.44
Outstanding at December 31, 2005	6,473	$ 23.60
Exercisable at December 31, 2003	2,828	$ 13.21
Exercisable at December 31, 2004	2,559	$ 14.66
Exercisable at December 31, 2005	1,903	$ 17.05

The weighted average fair value of an option to purchase one share of common stock granted during 2005, 2004 and 2003 was $25.21, $12.46 and $7.41, respectively. The fair value of each stock option granted is estimated as of the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions.

	2005	2004	2003
Dividend yield	None	None	None
Expected volatility	38.13%	40.94%	40.16%
Risk-free interest rate	3.76%	3.25%	3.48%
Expected option life	6.5 Years	6.5 Years	6.5 Years

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes information about stock options outstanding and exercisable at December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Underlying Options (In thousands)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Underlying Options (In thousands)	Weighted Average Exercise Price
$ 7.97 to $10.00	50	2.5 years	$ 8.28	50	$ 8.28
10.01 to 12.50	166	2.2 years	11.82	166	11.82
12.51 to 15.00	511	4.2 years	14.68	491	14.68
15.01 to 17.50	1,350	6.6 years	16.61	517	16.60
17.51 to 22.50	1,054	6.3 years	18.99	493	19.03
22.51 to 27.50	1,022	8.2 years	24.77	121	24.59
27.51 to 35.00	1,875	9.0 years	31.07	65	29.52
35.01 to 41.72	445	9.4 years	37.97		
	6,473	7.4 years	$ 23.60	1,903	$ 17.05

Common stock issued upon the exercise of non-qualified stock options results in a tax deduction for us equivalent to the compensation income recognized by the option holder. For financial reporting purposes, the tax effect of this deduction is accounted for as a credit to additional paid-in capital rather than as a reduction of income tax expense. The exercise of stock options during 2005, 2004 and 2003 resulted in a tax benefit to us of approximately $17 million, $6 million and $5 million, respectively.

At December 31, 2005, we had approximately 4.4 million additional shares available for issuance pursuant to our existing employee plans. Of the additional shares available at December 31, 2005, only 2.2 million could be granted as restricted shares. Grants of restricted stock under the 2004 Omnibus Stock Plan reduce the total number of shares available under that plan by two times the number of shares issued as restricted stock.

Restricted Shares

At December 31, 2005, our employees held 1.3 million shares of our common stock that were subject to forfeiture. About 725,000 of these restricted shares fully vest on the ninth anniversary of the date of grant, but vesting may be accelerated if certain targets are met. Substantially all of the remaining shares may vest in whole or in part in 2008, 2009 and 2010. The percentage of the shares vesting, if any, in each respective year is subject to the achievement of certain targets as identified in the agreement. For a discussion of the number of shares of common stock available for grant to employees as restricted shares, please see the immediately preceding paragraph.

Under our non-employee director restricted stock plan as in effect on December 31, 2005, immediately after each annual meeting of our stockholders, each of our non-employee directors then in office received a number of restricted shares determined by dividing $30,000 by the fair market value of one share of our common stock on the date of the annual meeting. In addition, new directors elected after an annual meeting received a number of restricted shares determined by dividing $30,000 by the fair market value of one share of our common stock on the date of their election. The forfeiture restrictions lapse on the day before the first annual meeting of stockholders following the date of issuance of the shares if the holder remains a director until that time. At December 31, 2005, 27,436 shares remained available for grants under this plan.

In accordance with APB 25, we recognize unearned compensation in connection with the grant of restricted shares equal to the fair value of our common stock on the date of grant. As the restricted shares

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

vest, we reduce unearned compensation and recognize compensation expense. The table below sets forth information about our restricted share grants and compensation expense relating to restricted share grants for each of the years in the three-year period ended December 31, 2005.

	Year Ended December 31,		
	2005	2004	2003
Restricted shares granted:			
Employee omnibus plans	707,600	103,800	531,400
Non-employee director plan[1]	9,284	12,124	13,328
Total	716,884	115,924	544,728
Weighted average fair value per restricted share granted	$ 37.25	$ 27.74	$ 16.66
Unearned compensation (in millions)	$ 27	$ 3	$ 9
Restricted shares cancelled:			
Employee omnibus plans	(56,000)	(7,200)	(98,600)
Non-employee director plan			
Total	(56,000)	(7,200)	(98,600)
Weighted average fair value per restricted share cancelled	$ 24.35	$ 18.46	$ 16.05
Unearned compensation (in millions)	$ (1)	$	$ (2)
Net unearned compensation (in millions)	$ 26	$ 3	$ 7
Compensation expense (in millions)[2]	$ 10	$ 4	$ 3

(1) Eleven directors received grants in 2005 and 2004 and eight in 2003.

(2) As restricted shares vest, the unearned compensation associated with those restricted shares (based on the fair value of our common stock on the date of grant of such restricted shares) is recorded as compensation expense.

Employee Stock Purchase Plan

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

At December 31, 2005, 110,059 shares of common stock were available for issuance pursuant to our stock purchase plan. Under the plan, we sold 55,931 shares in 2005 at a weighted average price of $29.42; 55,658 shares in 2004 at a weighted average price of $21.24; and 61,650 shares in 2003 at a weighted average price of $15.52. In accordance with APB 25 and related interpretations, we have not recognized any compensation expense with respect to the plan.

The weighted average fair value of an option to purchase one share of our common stock was $10.25, $7.48 and $5.45 during 2005, 2004 and 2003, respectively. The fair value of each option granted under the

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

stock purchase plan is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions for grants in 2005, 2004 and 2003:

	2005	2004	2003
Dividend yield	None	None	None
Expected volatility	32.24%	25.87%	20.83%
Risk-free interest rate	2.98%	1.32%	1.10%
Expected option life	6 Months	6 Months	6 Months

13. Pension Plan Obligation:

As a result of our acquisition of EEX in November 2002, we assumed responsibility for a defined pension benefit plan for current and former employees of EEX and its subsidiaries. The plan was amended, effective March 31, 2003, to cease all future retirement benefit accruals. After March 31, 2003, no participant has earned any further benefit accruals under the plan participant benefits were frozen as of March 31, 2003 and the benefits will not increase based upon future service completed or compensation received after that date. Accrued pension costs are funded based upon applicable requirements of federal law and deductibility for federal income tax purposes. The components of the pension plan obligation and its funded status are as follows:

	2005	2004
	(In millions)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ (27)	$ (28)
Service cost		
Interest cost	(2)	(2)
Assumption loss due to discount rate change		
Benefits paid	1	2
Actuarial gain (loss)	(2)	1
Benefit obligation at end of year	$ (30)	$ (27)
Change in plan assets:		
Fair value of plan assets at beginning of year	$ 22	$ 21
Actual return on plan assets	1	3
Employer contributions	1	
Benefits paid	(1)	(2)
Fair value of plan assets at end of year	$ 23	$ 22
Obligation and funded status:		

Fair value of plan assets	$ 23	$ 22
Benefit obligation	(30)	(27)
Funded status	(7)	(5)
Unrecognized net (gain) or loss	1	(3)
Net amount recognized	$ (6)	$ (8)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2005	2004
	(In millions)	
Amounts recognized on our consolidated balance sheet consist of:		
Prepaid benefit cost	$	$
Accrued benefit cost	(7)	(8)
Intangible assets		
Accumulated other comprehensive loss	1	
Net amount recognized	$ (6)	$ (8)
Components of net periodic benefit cost:		
Service cost	$	$
Interest cost	2	2
Expected return on plan assets	(2)	
Net periodic benefit cost	$	$ 2
Additional Information:		
Accumulated benefit obligation	$ (30)	$ (27)
Decrease (increase) in minimum pension liability included in other comprehensive income	(1)	1

	2005	2004
The weighted average assumptions used to determine the benefit obligation of the pension plan at December 31 were:		
Discount rate	5.75%	6.00%
Rate of compensation increase	N/A	N/A
Cost of living	3.00%	3.00%
The weighted average assumptions used to determine the net periodic pension benefit cost for the years ended December 31 were:		
Discount rate	6.00%	6.00%
Expected long-term rate of return on plan assets	8.00%	8.00%
Rate of compensation increase	N/A	N/A
Cost of living	3.00%	3.00%

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

We have developed an investment policy to invest in a broad range of securities. The diversified portfolio aims to maximize investment return without exposure to risk levels above those determined by us. The investment policy takes into consideration the retirement plan s benefit obligations including the expected

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

timing of benefit payments. The following is the allocation of the plan s assets by category at December 31, 2005 and 2004 as well as the target allocation of assets for 2006.

	Target Allocation 2006	Percentage of Plan Assets at December 31 2005	2004
Plan Asset Categories:			
Equity securities	40-60%	51%	56%
Debt securities	40-60%	48%	44%
Other	0-10%	1%	
Total		100%	100%

During 2006, we do not anticipate making any contributions to the plan.

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

2006	$ 1
2007	1
2008	1
2009	1
2010	1
2011 2015	8

14. Employee Benefit Plans:

Post-Retirement Medical Plan

We sponsor a post-retirement medical plan that covers all retired employees until they attain the age of 65. Our accumulated benefit obligation at December 31, 2005 was $4 million and our accrued benefit cost was $2 million and our net periodic benefit cost has been approximately $1 million per year.

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

2006 2010	$ 1
2011 2015	2

Incentive Compensation Plan

Effective January 1, 2003, our Board of Directors adopted our 2003 incentive compensation plan. The plan provides for the creation each calendar year of an award pool that is generally equal to 5% of our adjusted net income (as defined in the plan) plus the revenues attributable to an overriding royalty interest bearing on the interests of investors that participate in certain of our activities. The plan is administered by the Compensation & Management Development Committee of our Board of Directors and award amounts are recommended by our chief executive officer. All employees are eligible for awards if employed on both October 1 and December 31 of the performance period. Awards under the plan may, and generally do, have both a current and a deferred component. Deferred awards are paid in four annual installments, each installment consisting of 25% of the deferred award, plus interest. Total expense under the plan for the years ended December 31, 2005, 2004 and 2003 was $42 million, $29 million and $20 million, respectively.

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

401(k) and Deferred Compensation Plans

We sponsor a 401(k) profit sharing plan under Section 401(k) of the Internal Revenue Code. This plan covers all of our employees other than employees of our foreign subsidiaries. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee s salary, subject to limitations imposed by the Internal Revenue Service. During 1997, we implemented a highly compensated employee deferred compensation plan. This non-qualified plan allows an eligible employee to defer a portion of his or her salary or bonus on an annual basis. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee s salary, subject to limitations imposed by the plan. Our contribution with respect to each participant in the deferred compensation plan is reduced by the amount of contribution made by us to our 401(k) plan for that participant. Our combined contributions to these two plans totaled $3 million, $2 million and $2 million for the years ended December 31, 2005, 2004 and 2003, respectively.

15. Commitments and Contingencies:

Lease Commitments

We have various commitments under non-cancellable operating lease agreements for office space, equipment and drilling rigs. The majority of these commitments are related to multi-year contracts for offshore drilling rigs. Future minimum payments required under our operating leases as of December 31, 2005 are as follows (in millions):

Year Ending December 31,	
2006	$ 47
2007	50
2008	34
2009	21
2010	5
Thereafter	17
Total minimum lease payments	$ 174

Rent expense with respect to our lease commitments for office space for the years ended December 31, 2005, 2004 and 2003 was $5 million, $4 million and $4 million, respectively.

Other Commitments

As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work related commitments for, among other things, drilling wells, obtaining and processing seismic data and fulfilling other cash commitments. At December 31, 2005, these work related commitments total $195 million and are comprised of $93 million in the United States and $102 million internationally.

Litigation

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.

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Stockholder Rights Plan:

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

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

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

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

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

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

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

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. Segment Information:

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

The following tables provide the geographic operating segment information required by SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information as well as results of operations of oil and gas producing activities required by SFAS No. 69, Disclosures about Oil and Gas Producing Activities as of and for the years ended December 31, 2005, 2004, and 2003. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Year Ended December 31, 2005:						
Oil and gas revenues	$ 1,689	$ 1	$ 72	$	$	$ 1,762
Operating expenses:						
Lease operating	190		15			205
Production and other taxes	58		6			64
Depreciation, depletion and amortization	510	1	10			521
Ceiling test writedown					10	10
Allocated income taxes	326		15			
Net income (loss) from oil and gas properties	$ 605	$	$ 26	$	$ (10)	
General and administrative						104
Other						(29)
Total operating expenses						875
Income from operations						887
Interest expense, net of interest income, capitalized interest and other						(22)
Commodity derivative expense						(322)
Income before income taxes						$ 543
Total long-lived assets	$ 4,226	$ 46	$ 87	$ 45	$ 6	$ 4,410

Additions to long-lived assets	$ 1,076	$ 35	$ 41	$ 8	$ 3	$ 1,163

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Year Ended December 31, 2004:						
Oil and gas revenues	$ 1,311	$ 3	$ 39	$	$	$ 1,353
Operating expenses:						
Lease operating	143	1	8			152
Production and other taxes	40		2			42
Depreciation, depletion and amortization	463	2	7			472
Ceiling test writedown		17				17
Allocated income taxes	233		8			
Net income (loss) from oil and gas properties	$ 432	$ (17)	$ 14	$	$	
General and administrative						84
Other						35
Total operating expenses						802
Income from operations						551
Interest expense, net of interest income, capitalized interest and other						(28)
Commodity derivative expense						(24)
Income before income taxes						$ 499
Total long-lived assets	$ 3,643	$ 26	$ 57	$ 37	$ 12	$ 3,775
Additions to long-lived assets	$ 1,743	$ 32	$ 63	$ 2	$ 5	$ 1,845

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Year Ended December 31, 2003:						
Oil and gas revenues	$ 1,017	$	$	$	$	$ 1,017
Operating expenses:						
Lease operating	125					125
Production and other taxes	32					32
Depreciation, depletion and amortization	395					395
Allocated income taxes	163					
Net income from oil and gas properties	$ 302	$	$	$	$	
General and administrative						62
Other						20
Total operating expenses						634
Income from operations						383
Interest expense and dividends, net of interest income, capitalized interest and other						(45)
Commodity derivative expense						(6)
Income from continuing operations before income taxes						$ 332
Total long-lived assets	$ 2,365	$ 11	$	$ 35	$ 7	$ 2,418
Additions to long-lived assets(1)	$ 762	$ 10	$	$ 5	$ 2	$ 779

(1) Includes $100 million for capitalized asset retirement obligations in the United States associated with our adoption of SFAS No. 143.

18. Supplemental Cash Flow Information:

	Year Ended December 31,		
	2005	2004	2003
		(In millions)	

Cash payments:			
Interest and dividend payments, net of interest capitalized of $46, $26 and $16 during 2005, 2004 and 2003, respectively	$ 25	$ 22	$ 42
Income tax payments	54	17	40
Non-cash items excluded from the statement of cash flows:			
Accrued capital expenditures	$ (66)	$ (33)	$ (23)
Asset retirement costs	(44)	(48)	(132)

19. Related Party Transaction:

David A. Trice, our Chairman, President and Chief Executive Officer, and Susan G. Riggs, our Treasurer, are minority owners of Huffco International L.L.C. In May 1997, prior to Mr. Trice and Ms. Riggs joining us, we acquired from Huffco an entity now known as Newfield China, LDC, the owner of a 12% interest in a

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

three field unit located on Blocks 04/36 and 05/36 in Bohai Bay, offshore China. We expect to receive 18% of production until our exploration and production costs have been recovered. Huffco retained preferred shares of Newfield China that provide for an aggregate dividend equal to 10% of the excess of proceeds received by Newfield China from the sale of oil, gas and other minerals over all costs incurred with respect to exploration and production in Block 05/36, plus the cash purchase price we paid Huffco for Newfield China ($6 million). At December 31, 2005, Newfield China had approximately $45 million of unrecovered costs. As a result, no dividends have been paid to date on its preferred shares. Newfield anticipates that it will begin paying preferred dividends in early 2007. Based on our estimate of the net present value of the proved reserves associated with Block 05/36, the indirect interests (through Huffco) in Newfield China s preferred shares held by Mr. Trice and Ms. Riggs had a net present value of approximately $225,000 and $86,000, respectively, at December 31, 2005.

20. Quarterly Results of Operations (Unaudited):

The results of operations by quarter for the years ended December 31, 2005 and 2004 are as follows:

	2005 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil and gas revenues	$ 413	$ 446	$ 460	$ 443
Income from operations[1]	197	216	243	231
Net income (loss)	60	104		184
Basic earnings per common share[2]	$ 0.48	$ 0.83	$	$ 1.46
Diluted earnings per common share[2]	$ 0.47	$ 0.82	$	$ 1.43

	2004 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil and gas revenues	$ 305	$ 283	$ 328	$ 437
Income from operations[3]	141	119	126	165
Net income	78	67	77	90
Basic earnings per common share[2]	$ 0.70	$ 0.60	$ 0.65	$ 0.73
Diluted earnings per common share[2]	$ 0.69	$ 0.59	$ 0.63	$ 0.72

(1) Income from operations for the third quarter of 2005 includes an unrealized loss on discontinued cash flow hedges of $65 million as a result of production deferrals experienced in the Gulf of Mexico related to Hurricanes Katrina and Rita. See Note 6, Commodity Derivative Instruments and Hedging Activities *Cash Flow Hedges.* Income from operations for the fourth quarter of 2005 includes a full cost ceiling test writedown of $10 related to certain of our nonproducing international operations and the recognition of a $22 million benefit related to our business interruption insurance coverage.

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

(3) Income from operations for the third quarter of 2004 includes a full cost ceiling test writedown of $7 million related to our operations in the U.K. North Sea. Income from operations for the fourth quarter of 2004 includes an additional $10 million ceiling test writedown related to the U.K. North Sea and a charge of $35 million related to the impairment of the floating production system and pipelines. See Note 1, Organization and Summary of Significant Accounting Policies *Oil and Gas Properties,* and Note 5, Oil and Gas Assets *Floating Production System and Pipelines.*

Table of Contents

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED

Costs incurred for oil and gas property acquisitions, exploration and development for each of the years in the three-year period ended December 31, 2005 are as follows (in millions):

	United States	United Kingdom	Malaysia	China	Other International	Total
2005:						
Property acquisitions:						
Unproved	$ 56	$ 3	$ 15	$ 1	$ 1	$ 76
Proved	26					26
Exploration[1]	805	27	23	2	2	859
Development[2]	189	5	3	5		202
Total costs incurred[3]	$ 1,076	$ 35	$ 41	$ 8	$ 3	$ 1,163
2004:						
Property acquisitions:[4]						
Unproved	$ 422	$ 7	$ 7	$ 1	$ 1	$ 438
Proved	560		44			604
Exploration[1]	618	25	9	1	4	657
Development[2]	143		3			146
Total costs incurred[5]	$ 1,743	$ 32	$ 63	$ 2	$ 5	$ 1,845
2003:						
Property acquisitions:						
Unproved	$ 39	$ 4	$	$ 1	$ 1	$ 45
Proved	137	3				140
Exploration[1]	408	2		4	1	415
Development[2]	78	1				79
Total costs incurred	$ 662	$ 10	$	$ 5	$ 2	$ 679

(1) Includes $254 million, $136 million and $155 million of United States costs for non-exploitation activities for 2005, 2004 and 2003, respectively, $26 million, $25 million and $2 million of United Kingdom costs for non-exploitation activities for 2005, 2004 and 2003, respectively, $17 million and $9 million of Malaysia costs for non-exploitation activities for 2005 and 2004, respectively, $1 million, $1 million and $4 million of China costs for non-exploitation activities for 2005, 2004 and 2003, respectively, and $2 million, $4 million and $1 million of Other International costs for non-exploitation activities for 2005, 2004 and 2003, respectively.

(2) Includes $44 million, $48 million and $32 million for 2005, 2004 and 2003, respectively, of asset retirement costs recorded in accordance with SFAS No. 143.

(3) Excludes $1 million and $9 million in property sales in the United States and United Kingdom, respectively, and $6 million in foreign currency translation adjustments. In addition, excludes the $10 million ceiling test writedown related to other international investments.

(4) Includes $344 million and $375 million recorded as unproved and proved property acquisition costs, respectively, related to the August 2004 acquisition of Inland Resources. These amounts represent the recorded fair value of the oil and gas assets. The cash consideration paid in the acquisition was approximately $575 million.

(5) Excludes $17 million in property sales in the United States and $2 million in foreign currency translation adjustments. Additionally, the $17 million ceiling test writedown in the United Kingdom is not presented as a reduction of capital expenditures.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Capitalized costs for our oil and gas producing activities consisted of the following at the end of each of the years in the three-year period ended December 31, 2005 (in millions):

	United States	United Kingdom	Malaysia	China	Other International	Total
December 31, 2005:						
Proved properties	$ 6,015	$ 30	$ 67	$ 45	$	$ 6,157
Unproved properties	824	18	37		6	885
	6,839	48	104	45	6	7,042
Accumulated depreciation, depletion and amortization	(2,613)	(2)	(17)			(2,632)
Net capitalized costs	$ 4,226	$ 46	$ 87	$ 45	$ 6	$ 4,410
December 31, 2004:						
Proved properties	$ 5,030	$ 3	$ 47	$	$	$ 5,080
Unproved properties	738	25	16	37	12	828
	5,768	28	63	37	12	5,908
Accumulated depreciation, depletion and amortization	(2,125)	(2)	(6)			(2,133)
Net capitalized costs	$ 3,643	$ 26	$ 57	$ 37	$ 12	$ 3,775
December 31, 2003:						
Proved properties	$ 3,743	$ 4	$	$	$	$ 3,747
Unproved properties	282	7		35	7	331
	4,025	11		35	7	4,078
Accumulated depreciation, depletion and amortization	(1,660)					(1,660)
Net capitalized costs	$ 2,365	$ 11	$	$ 35	$ 7	$ 2,418

Table of Contents

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

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

Estimated Net Quantities of Proved Oil and Gas Reserves

The following table sets forth our total net proved reserves and our total net proved developed reserves as of December 31, 2002, 2003, 2004 and 2005 and the changes in our total net proved reserves during the three-year period ended December 31, 2005, as estimated by our petroleum engineering staff:

	Oil, Condensate and Natural Gas Liquids (MMBbls)					**Natural Gas (Bcf)**			**Total (Bcfe)**			
	U.S.	**U.K.**	**Malaysia**	**China**	**Total**	**U.S.**	**U.K.**	**Total**	**U.S.**	**U.K.**	**Malaysia**	**China**
loped loped of:												
31, 2002	34.0				34.0	977.1		977.1	1,181.3			
imates	0.7				0.7	(4.2)		(4.2)				
and other	6.3				6.3	200.4		200.4	238.0			
	2.9				2.9	101.3	2.6	103.9	118.3	2.6		
perties						(2.8)		(2.8)	(2.8)			
	(6.1)				(6.1)	(184.2)		(184.2)	(220.6)			
31, 2003	37.8				37.8	1,087.6	2.6	1,090.2	1,314.2	2.6		
imates	1.2				1.2	(1.9)	(0.5)	(2.4)	5.3	(0.5)		
and other	5.3				5.3	230.9		230.9	262.4			
	47.8		6.6		54.4	131.4		131.4	418.2		39.6	
perties	(0.6)				(0.6)	(10.8)		(10.8)	(14.3)			
	(6.7)		(0.9)		(7.6)	(197.6)	(0.6)	(198.2)	(237.7)	(0.6)	(5.3)	

31, 2004	84.8		5.7		90.5	1,239.6	1.5	1,241.1	1,748.1	1.5	34.3	
f												
imates	0.8		(0.1)		0.7	10.7		10.7	15.6		(0.8)	
and other												
	9.2	0.8	4.7	5.3	20.0	249.3	64.1	313.4	304.5	69.2	28.0	31.5
f												
	0.3				0.3	16.9		16.9	18.9			
perties	(0.2)				(0.2)	(6.1)	(1.3)	(7.4)	(7.1)	(1.2)		
	(8.4)		(1.3)		(9.7)	(183.2)	(0.2)	(183.4)	(233.8)	(0.1)	(7.7)	
31, 2005	86.5	0.8	9.0	5.3	101.6	1,327.2	64.1	1,391.3	1,846.2	69.4	53.8	31.5
loped of:												
1, 2002	32.4				32.4	905.1		905.1	1,099.6			
1, 2003	30.7				30.7	955.8	2.5	958.3	1,139.9	2.6		
1, 2004	49.7		5.7		55.4	1,003.9	1.4	1,005.3	1,302.2	1.4	34.3	
1, 2005	54.6		4.3		58.9	1,010.2		1,010.2	1,338.0		25.8	

(1) Substantially all of the purchases of U.S. oil, condensate and natural gas liquids relates our August 2004 acquisition of Inland Resources.

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

Table of Contents

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

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

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

We believe that in reviewing the information that follows the following factors should be taken into account:

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

Under the standardized measure, future cash inflows were estimated by applying year-end oil and gas prices applicable to our reserves to the estimated future production of year-end proved reserves. Future cash inflows do not reflect the impact of future production that is subject to open hedge positions (see Note 6, Commodity Derivative Instruments and Hedging Activities). Future cash inflows were reduced by estimated future development, abandonment and production costs based on year-end costs in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying year-end statutory tax rates to aggregate future pre-tax net cash flows reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% discount rate and year-end prices and costs are required by SFAS No. 69.

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

Table of Contents

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

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

	U.S.	U.K.	Malaysia	China	Total
			(In millions)		
2005:					
Future cash inflows	$ 15,458	$ 658	$ 568	$ 268	$ 16,952
Less related future:					
Production costs	(2,688)	(65)	(334)	(55)	(3,142)
Development and abandonment costs	(1,192)	(146)	(47)	(27)	(1,412)
Future net cash flows before income taxes	11,578	447	187	186	12,398
Future income tax expense	(3,585)	(232)	(88)	(54)	(3,959)
Future net cash flows before 10% discount	7,993	215	99	132	8,439
10% annual discount for estimating timing of cash flows	(3,259)	(57)	(19)	(51)	(3,386)
Standardized measure of discounted future net cash flows	$ 4,734	$ 158	$ 80	$ 81	$ 5,053
2004:					
Future cash inflows	$ 10,718	$ 7	$ 219	$	$ 10,944
Less related future:					
Production costs	(2,067)	(4)	(127)		(2,198)
Development and abandonment costs	(886)	(1)	(10)		(897)
Future net cash flows before income taxes	7,765	2	82		7,849
Future income tax expense	(2,149)	(1)	(31)		(2,181)
Future net cash flows before 10% discount	5,616	1	51		5,668
10% annual discount for estimating timing of cash flows	(2,059)		(7)		(2,066)
Standardized measure of discounted future net cash flows	$ 3,557	$ 1	$ 44	$	$ 3,602
2003:					
Future cash inflows	$ 7,617	$ 12	$	$	$ 7,629
Less related future:					

Production costs	(1,374)	(6)			(1,380)
Development and abandonment costs	(450)	(1)			(451)
Future net cash flows before income taxes	5,793	5			5,798
Future income tax expense	(1,461)	(2)			(1,463)
Future net cash flows before 10% discount	4,332	3			4,335
10% annual discount for estimating timing of cash flows	(1,400)				(1,400)
Standardized measure of discounted future net cash flows	$ 2,932	$ 3	$	$	$ 2,935

92

Table of Contents

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Set forth in the table below is a summary of the changes in the standardized measure of discounted future net cash flows for our proved oil and gas reserves during each of the years in the three-year period ended December 31, 2005:

	U.S.	U.K.	Malaysia (In millions)	China	Total
2005:					
Beginning of the period	$ 3,557	$ 1	$ 44	$	$ 3,602
Revisions of previous estimates:					
Changes in prices and costs	1,729		25		1,754
Changes in quantities	(186)		(1)		(187)
Changes in future development costs	(91)				(91)
Development costs incurred during the period	180		(2)		178
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	1,103	324	81	111	1,619
Purchases and sales of reserves in place, net	18	(1)			17
Accretion of discount	356		5		361
Sales of oil and gas, net of production costs	(1,160)		(25)		(1,185)
Net change in income taxes	(738)	(166)	(49)	(30)	(983)
Production timing and other	(34)		2		(32)
Net increase	1,177	157	36	81	1,451
End of the period	$ 4,734	$ 158	$ 80	$ 81	$ 5,053
2004:					
Beginning of the period	$ 2,932	$ 3	$	$	$ 2,935
Revisions of previous estimates:					
Changes in prices and costs	157				157
Changes in quantities	(4)				(4)
Development costs incurred during the period	135				135
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	734				734
Purchases and sales of reserves in place, net	855		81		936
Accretion of discount	293				293
Sales of oil and gas, net of production costs	(1,130)	(1)	(11)		(1,142)
Net change in income taxes	(343)		(26)		(369)
Production timing and other	(72)	(1)			(73)

Net increase (decrease)		625		(2)		44				667
End of the period	$	3,557	$	1	$	44	$		$	3,602

93

Table of Contents

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

	U.S.	U.K.	Malaysia	China	Total
			(In millions)		
2003:					
Beginning of the period	$ 2,247	$	$	$	$ 2,247
Revisions of previous estimates:					
Changes in prices and costs	576				576
Changes in quantities					
Development costs incurred during the period	63				63
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	710				710
Purchases and sales of reserves in place, net	296	4			300
Accretion of discount	225				225
Sales of oil and gas, net of production costs	(853)				(853)
Net change in income taxes	(246)	(1)			(247)
Production timing and other	(86)				(86)
Net increase	685	3			688
End of the period	$ 2,932	$ 3	$	$	$ 2,935

94

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

None.

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

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2005 in ensuring that material information was accumulated and communicated to management, and made known to our Chief Executive Officer and Chief Financial Officer, on a timely basis to allow disclosure as required in this report.

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

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

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2005 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Management s report on internal control over financial reporting for 2004 excluded the Rocky Mountains Division from its assessment because the division was formed with the acquisition of Inland Resources in a purchase business combination in late 2004. During 2005, management s assessment included the internal controls of our Rocky Mountains Division.

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

None.

PART III

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

The information required by Item 10 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2006 annual meeting of stockholders to be held on May 4, 2006 and to the information set forth in Item 4A of this report.

Corporate Code of Business Conduct and Ethics

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

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

Corporate Governance Guidelines

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

Committee Charters

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

Section 16(a) Beneficial Ownership Reporting Compliance

Information regarding Section 16(a) beneficial ownership reporting compliance is incorporated herein by reference to such information as set forth in the proxy statement for our 2006 annual meeting of stockholders to be held on May 4, 2006.

Certifications

The New York Stock Exchange requires the chief executive officer of each listed company to certify annually that he or she is not aware of any violation by the company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. Our chief executive officer provided such certification to the NYSE in 2005. In addition, the certifications of our chief executive officer and chief financial officer required by Section 302 of the Sarbanes-Oxley Act have been filed as exhibits to this report and to our annual report on Form 10-K for the year ended December 31, 2004.

After joining our Board of Directors in November 2004, J. Terry Strange was appointed to the Audit Committee of our Board of Directors. Mr. Strange also served on the audit committees of four other public companies. Our Board of Directors determined that such simultaneous service did not impair the ability of Mr. Strange to effectively serve on our Audit Committee. However, disclosure of this determination was inadvertently omitted from our annual report for the year ended December 31, 2004. Our chief executive officer s certification to the NYSE was qualified by this omission.

Item 11. ***Executive Compensation***

The information required by Item 11 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2006 annual meeting.

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

The information required by Item 12 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2006 annual meeting.

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

The information required by Item 13 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2006 annual meeting.

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

The information required by Item 14 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2006 annual meeting.

Table of Contents

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

Financial Statements

Reference is made to the index set forth on page 48 of this report.

Financial Statement Schedules

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

Exhibits

Exhibit Number	Title
3.1	Second Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield s Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, setting forth the terms of the Series A Junior Participating Preferred Stock, par value $0.01 per share (incorporated by reference to Exhibit 3.5 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-12534))
*3.2	Restated Bylaws of Newfield (as amended by Amendment No. 1 thereto adopted January 31, 2000 and Amendment No. 2 thereto adopted July 28, 2005)
4.1	Rights Agreement, dated as of February 12, 1999, between Newfield and ChaseMellon Shareholder Services L.L.C., as Rights Agent, specifying the terms of the Rights to Purchase Series A Junior Participating Preferred Stock, par value $0.01 per share, of Newfield (incorporated by reference to Exhibit 1 to Newfield s Registration Statement on Form 8-A filed with the SEC on February 18, 1999 (File No. 1-12534))
4.2	Indenture dated as of October 15, 1997 among Newfield, as issuer, and Wachovia Bank, National Association (formerly First Union National Bank), as trustee (incorporated by reference to Exhibit 4.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-39563))
4.3	Senior Indenture dated as of February 28, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 28, 2001 (File No. 1-12534))
4.4	

	Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.5 of Newfield s Registration Statement on Form S-3 (Registration No. 333-71348))
4.4.1	First Supplemental Indenture, dated as of August 13, 2002, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 of Newfield s Current Report on Form 8-K filed with the SEC on August 13, 2002 (File No. 1-12534))
4.4.2	Second Supplemental Indenture, dated as of August 18, 2004, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.6.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-122157))

Table of Contents

Exhibit Number	Title
10.1	Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1 to Newfield s Registration Statement on Form S-8 (Registration No. 33-92182))
10.1.1	First Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.1.2	Second Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.2	Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1.1 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.1	Amendment of 1998 Omnibus Stock Plan, dated May 7, 1998 (incorporated by reference to Exhibit 4.1.2 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.2	Second Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (as amended on May 7, 1998) (incorporated by reference to Exhibit 10.2 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.2.3	Third Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 99.2 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.3	Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.7.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
10.3.1	First Amendment to Newfield Exploration Company 2000 Omnibus Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.3 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.3.2	Second Amendment to Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 99.3 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.3.3	Form of TSR 2003 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf and Mark J. Spicer dated as of February 12, 2003 (incorporated by reference to Exhibit 10.3.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.4	Newfield Exploration Company 2004 Omnibus Stock Plan (incorporated by reference to Exhibit 10.2 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004 (File No. 1-12534))
10.4.1	First Amendment to Newfield Exploration Company 2004 Omnibus Stock Plan (incorporated by reference to Exhibit 99.4 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.4.2	Second Amendment to Newfield Exploration Company 2004 Omnibus Stock Plan (incorporated by reference to Exhibit 10.4 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.4.3	Form of TSR 2005 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine,

Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 8, 2005 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 11, 2005 (File No. 1-12534))

Table of Contents

Exhibit Number	Title
10.4.4	Form of TSR 2006 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 14, 2006 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.5	Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10.18 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
10.6	Newfield Employee 1993 Incentive Compensation Plan (incorporated by reference to Exhibit 10.5 to Newfield s Registration Statement on Form S-1 (Registration No. 33-69540))
10.6.1	Amendment to Newfield Employee 1993 Incentive Compensation Plan (effective as of February 14, 2002) (incorporated by reference to Exhibit 10.9.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
10.7	Amended and Restated Newfield Exploration Company 2003 Incentive Compensation Plan (incorporated by reference to Exhibit 10.7 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.8	Newfield Exploration Company Deferred Compensation Plan (incorporated by reference to Exhibit 10.11 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))
10.9	Newfield Exploration Company Change of Control Severance Plan (incorporated by reference to Exhibit 10.9 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.9.1	First Amendment to Newfield Exploration Company Change of Control Severance Plan (incorporated by reference to Exhibit 10.3 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.10.1	Form of Change of Control Severance Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew and Terry W. Rathert dated effective as of February 17, 2005 (incorporated by reference to Exhibit 10.10 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.10.2	Form of Change of Control Severance Agreement between Newfield and each of Lee K. Boothby, George T. Dunn, Gary D. Packer and William D. Schneider dated effective as of February 17, 2005 (incorporated by reference to Exhibit 10.11 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.10.3	Form of First Amendment to Change of Control Severance Agreement between Newfield and each executive officer who is a party to such an agreement (incorporated by reference to Exhibit 10.2 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.11	Form of Indemnification Agreement between Newfield and each of its directors and executive officers (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005 (File No. 1-12534))
10.12	Resolution of Members Establishing the Preferences, Limitations and Relative Rights of Series A Preferred Shares of Huffco China, LDC dated May 14, 1997 (incorporated by reference to Exhibit 10.15 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))

10.13	Credit Agreement, dated as of December 2, 2005, among Newfield Exploration Company, JP Morgan Chase Bank, N.A., as Administrative Agent and a lender, and the other agents and lenders party thereto (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on December 6, 2005 (File No. 1-12534))
*21.1	List of Significant Subsidiaries
**23.1	Consent of PricewaterhouseCoopers LLP
**31.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

Table of Contents

Exhibit Number	Title
**31.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
**32.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
**32.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed or furnished with our Annual Report on Form 10-K for the year ended December 31, 2005 as originally filed on March 3, 2006.

** Filed or furnished herewith.

Identifies management contracts and compensatory plans or arrangements.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 28th day of February, 2007.

NEWFIELD EXPLORATION COMPANY

By: /s/ DAVID A. TRICE
David A. Trice
Chairman, President and Chief Executive Officer

INDEX TO EXHIBITS

Exhibit Number	Title
3.1	Second Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield s Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, setting forth the terms of the Series A Junior Participating Preferred Stock, par value $0.01 per share (incorporated by reference to Exhibit 3.5 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-12534))
*3.2	Restated Bylaws of Newfield (as amended by Amendment No. 1 thereto adopted January 31, 2000 and Amendment No. 2 thereto adopted July 28, 2005)
4.1	Rights Agreement, dated as of February 12, 1999, between Newfield and ChaseMellon Shareholder Services L.L.C., as Rights Agent, specifying the terms of the Rights to Purchase Series A Junior Participating Preferred Stock, par value $0.01 per share, of Newfield (incorporated by reference to Exhibit 1 to Newfield s Registration Statement on Form 8-A filed with the SEC on February 18, 1999 (File No. 1-12534))
4.2	Indenture dated as of October 15, 1997 among Newfield, as issuer, and Wachovia Bank, National Association (formerly First Union National Bank), as trustee (incorporated by reference to Exhibit 4.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-39563))
4.3	Senior Indenture dated as of February 28, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 28, 2001 (File No. 1-12534))
4.4	Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.5 of Newfield s Registration Statement on Form S-3 (Registration No. 333-71348))
4.4.1	First Supplemental Indenture, dated as of August 13, 2002, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 of Newfield s Current Report on Form 8-K filed with the SEC on August 13, 2002 (File No. 1-12534))
4.4.2	Second Supplemental Indenture, dated as of August 18, 2004, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.6.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-122157))
10.1	Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1 to Newfield s Registration Statement on Form S-8 (Registration No. 33-92182))
10.1.1	First Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))

10.1.2	Second Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.2	Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1.1 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.1	Amendment of 1998 Omnibus Stock Plan, dated May 7, 1998 (incorporated by reference to Exhibit 4.1.2 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))

Exhibit Number	Title
10.2.2	Second Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (as amended on May 7, 1998) (incorporated by reference to Exhibit 10.2 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.2.3	Third Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 99.2 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.3	Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.7.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
10.3.1	First Amendment to Newfield Exploration Company 2000 Omnibus Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.3 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.3.2	Second Amendment to Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 99.3 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.3.3	Form of TSR 2003 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf and Mark J. Spicer dated as of February 12, 2003 (incorporated by reference to Exhibit 10.3.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.4	Newfield Exploration Company 2004 Omnibus Stock Plan (incorporated by reference to Exhibit 10.2 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004 (File No. 1-12534))
10.4.1	First Amendment to Newfield Exploration Company 2004 Omnibus Stock Plan (incorporated by reference to Exhibit 99.4 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.4.2	Second Amendment to Newfield Exploration Company 2004 Omnibus Stock Plan (incorporated by reference to Exhibit 10.4 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.4.3	Form of TSR 2005 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 8, 2005 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 11, 2005 (File No. 1-12534))
10.4.4	Form of TSR 2006 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 14, 2006 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.5	Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10.18 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))

10.6	Newfield Employee 1993 Incentive Compensation Plan (incorporated by reference to Exhibit 10.5 to Newfield s Registration Statement on Form S-1 (Registration No. 33-69540))
10.6.1	Amendment to Newfield Employee 1993 Incentive Compensation Plan (effective as of February 14, 2002) (incorporated by reference to Exhibit 10.9.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
10.7	Amended and Restated Newfield Exploration Company 2003 Incentive Compensation Plan (incorporated by reference to Exhibit 10.7 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))

Table of Contents

Exhibit Number	Title
10.8	Newfield Exploration Company Deferred Compensation Plan (incorporated by reference to Exhibit 10.11 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))
10.9	Newfield Exploration Company Change of Control Severance Plan (incorporated by reference to Exhibit 10.9 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.9.1	First Amendment to Newfield Exploration Company Change of Control Severance Plan (incorporated by reference to Exhibit 10.3 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.10.1	Form of Change of Control Severance Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew and Terry W. Rathert dated effective as of February 17, 2005 (incorporated by reference to Exhibit 10.10 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.10.2	Form of Change of Control Severance Agreement between Newfield and each of Lee K. Boothby, George T. Dunn, Gary D. Packer and William D. Schneider dated effective as of February 17, 2005 (incorporated by reference to Exhibit 10.11 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.10.3	Form of First Amendment to Change of Control Severance Agreement between Newfield and each executive officer who is a party to such an agreement (incorporated by reference to Exhibit 10.2 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.11	Form of Indemnification Agreement between Newfield and each of its directors and executive officers (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005 (File No. 1-12534))
10.12	Resolution of Members Establishing the Preferences, Limitations and Relative Rights of Series A Preferred Shares of Huffco China, LDC dated May 14, 1997 (incorporated by reference to Exhibit 10.15 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))
10.13	Credit Agreement, dated as of December 2, 2005, among Newfield Exploration Company, JP Morgan Chase Bank, N.A., as Administrative Agent and a lender, and the other agents and lenders party thereto (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on December 6, 2005 (File No. 1-12534))
*21.1	List of Significant Subsidiaries
**23.1	Consent of PricewaterhouseCoopers LLP
**31.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
**31.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
**32.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
**32.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed or furnished with our Annual Report on Form 10-K for the year ended December 31, 2005 as originally filed on March 3, 2006.

** Filed or furnished herewith.

Identifies management contracts and compensatory plans or arrangements.