NEWFIELD EXPLORATION CO /DE/
Form 10-Q
October 31, 2006

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended September 30, 2006

OR

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

For the Transition Period from ____________to____________.

Commission File Number: 1-12534

NEWFIELD EXPLORATION COMPANY
(Exact name of Registrant as specified in its charter)

Delaware	**72-1133047**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

363 North Sam Houston Parkway East
Suite 2020
Houston, Texas 77060
(Address and Zip Code of principal executive offices)

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

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 ¨

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 ¨ Non-accelerated filer ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes ¨ No þ

As of October 30, 2006, there were 128,976,619 shares of the Registrant's Common Stock, par value $0.01 per share, outstanding.

TABLE OF CONTENTS

Table of Contents

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEET
(In millions, except share data)
(Unaudited)

	September 30, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 265	$ 39
Short-term investments	30	—
Accounts receivable	318	370
Inventories	42	22
Derivative assets	275	10
Deferred taxes	—	46
Other current assets	74	53
Total current assets	1,004	540
Oil and gas properties (full cost method, of which $999 at September 30, 2006 and $901 at December 31, 2005 were excluded from amortization)	8,326	7,042
Less—accumulated depreciation, depletion and amortization	(3,054)	(2,632)
	5,272	4,410
Furniture, fixtures and equipment, net	21	20
Derivative assets	17	17
Other assets	20	23
Deferred taxes	11	9
Goodwill	62	62
Total assets	$ 6,407	$ 5,081
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 74	$ 41
Accrued liabilities	587	454
Advances from joint owners	70	29
Asset retirement obligation	49	47
Deferred taxes	53	—
Derivative liabilities	104	99
Total current liabilities	937	670
Other liabilities	23	21
Derivative liabilities	192	209
Long-term debt	1,171	870
Asset retirement obligation	223	213
Deferred taxes	915	720
Total long-term liabilities	2,524	2,033

Commitments and contingencies (Note 5)		—		—
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 September 30, 2006 and December 31, 2005; 130,828,550 and 129,356,162 shares issued and outstanding at September 30, 2006 and December 31, 2005, respectively)		1		1
Additional paid-in capital		1,182		1,186
Treasury stock (at cost; 1,879,081 and 1,815,594 shares at September 30, 2006 and December 31, 2005, respectively)		(31)		(27)
Unearned compensation		—		(34)
Accumulated other comprehensive income (loss):				
Foreign currency translation adjustment		5		(4)
Commodity derivatives		(16)		(40)
Retained earnings		1,805		1,296
Total stockholders' equity		2,946		2,378
Total liabilities and stockholders' equity	$	6,407	$	5,081

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

1

Table of Contents

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF INCOME
(In millions, except per share data)
(Unaudited)

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Oil and gas revenues	$ 425	$ 460	$ 1,246	$ 1,319
Operating expenses:				
Lease operating	36	55	155	150
Production and other taxes	12	18	43	41
Depreciation, depletion and amortization	159	127	434	403
Ceiling test writedown	6	—	6	—
General and administrative	34	25	92	76
Other	(6)	(7)	(11)	(7)
Total operating expenses	241	218	719	663
Income from operations	184	242	527	656
Other income (expenses):				
Interest expense	(23)	(17)	(65)	(54)
Capitalized interest	11	11	33	34
Commodity derivative income (expense)	247	(238)	299	(393)
Other	2	2	7	3
	237	(242)	274	(410)
Income before income taxes	421	—	801	246
Income tax provision (benefit):				
Current	18	29	30	68
Deferred	137	(29)	262	14
	155	—	292	82
Net income	$ 266	$ —	$ 509	$ 164
Earnings per share:				
Basic	$ 2.10	$ —	$ 4.02	$ 1.31
Diluted	$ 2.06	$ —	$ 3.95	$ 1.29
Weighted average number of shares outstanding for basic earnings per share	126	126	127	125
Weighted average number of shares outstanding for diluted earnings per share	129	126	129	128

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

Table of Contents

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)
(Unaudited)

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Cash flows from operating activities:		
Net income	$ 509	$ 164
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	434	403
Deferred taxes	262	14
Stock-based compensation	23	5
Early redemption cost on senior subordinated notes	8	—
Ceiling test writedown	6	—
Gain on sale of floating production system	—	(7)
Unrealized commodity derivative (income) expense	(226)	357
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	82	(12)
Increase in inventories	(18)	(11)
Increase in other current assets	(20)	(11)
Decrease in other assets	12	4
Increase (decrease) in accounts payable and accrued liabilities	41	(17)
Decrease in commodity derivative liabilities	(13)	(14)
Increase in advances from joint owners	40	5
Increase in other liabilities	5	7
Net cash provided by operating activities	1,145	887
Cash flows from investing activities:		
Additions to oil and gas properties	(1,244)	(762)
Insurance recoveries	45	—
Proceeds from sale of oil and gas properties		11
Proceeds from sale of floating production system		7
Additions to furniture, fixtures and equipment	(4)	(4)
Purchases of short-term investments	(541)	—
Redemption of short-term investments	511	—
Net cash used in investing activities	(1,233)	(748)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	491	604
Repayments of borrowings under credit arrangements	(491)	(724)
Proceeds from issuance of senior subordinated notes	550	—
Repayment of senior subordinated notes	(250)	—
Proceeds from issuances of common stock	9	28

Stock-based compensation excess tax benefit		3		
Purchases of treasury stock		(3)		—
Net cash provided by (used in) financing activities		309		(92)
Effect of exchange rate changes on cash and cash equivalents		5		(3)
Increase in cash and cash equivalents		226		44
Cash and cash equivalents, beginning of period		39		58
Cash and cash equivalents, end of period	$	265	$	102

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

3

Table of Contents

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In millions)
(Unaudited)

	Common Stock		Treasury Stock		Additional Paid-in	Unearned	Retained	Accumulated Other Comprehensive Income	Total Stockholders'
	Shares	Amount	Shares	Amount	Capital	Compensation	Earnings	(Loss)	Equity
Balance, December 31, 2005	129.4	$ 1	(1.8)	$ (27)	$ 1,186	$ (34)	$ 1,296	$ (44)	$ 2,378
Issuance of common and restricted stock	1.4				9				9
Stock-based compensation					18				18
Treasury stock, at cost			(0.1)	(4)					(4)
Excess tax benefit from stock-based compensation					3				3
Adoption of SFAS No. 123(R)					(34)	34			
Comprehensive income:									
Net income							509		509
Foreign currency translation adjustment, net of tax of ($5)								9	9
Reclassification adjustments for settled hedging positions, net of tax of $15								(28)	(28)
Changes in fair value of outstanding hedging positions, net of tax of ($28)								52	52
Total comprehensive income									542
Balance, September 30, 2006	130.8	$ 1	(1.9)	$ (31)	$ 1,182	$	$ 1,805	$ (11)	$ 2,946

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
(Unaudited)

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 “we,” “us” or “our” are to Newfield Exploration Company and its subsidiaries.

These unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to state fairly our financial position as of, and results of operations for, the periods presented. These financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the United States of America. Interim period results are not necessarily indicative of results of operations or cash flows for a full year.

These financial statements and notes should be read in conjunction with our audited consolidated financial statements and the notes thereto included in our annual report on Form 10-K for the year ended December 31, 2005.

Dependence on Oil and Gas Prices

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for natural gas and oil. Historically, the energy markets have been very volatile and it is likely that oil and gas prices will continue to 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 our consolidated 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 related to our proved oil and gas reserves.

Investments

Investments consist of highly liquid investment grade commercial paper with a maturity of less than six months. These investments are classified as "available-for-sale." Accordingly, unrealized gains and losses and the related deferred income tax effects are excluded from earnings and reported as a separate component of stockholders' equity. Realized gains or losses are computed based on specific identification of the securities sold.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Insurance Recoveries

On August 11, 2006, we reached an agreement with our underwriters to settle all claims related to Hurricanes Katrina and Rita (business interruption, property damage and control of well/operator’s extra expense) for $235 million. After adjustments for applicable deductibles and amounts already collected for previously submitted claims, we received net proceeds of $190 million during the third quarter of 2006. Based on the nature of the coverage provided under the policies, we have recorded a cumulative inception to date credit of $58 million to other operating expense (of which, credits of $6 million and $36 million were recorded during the three and nine months ended September 30, 2006, respectively) for amounts attributable to business interruption coverage; a credit of $48 million to our domestic full cost pool (all of which was recorded during the three months ended September 30, 2006) for amounts attributable to property damage coverage; and a cumulative $129 million credit to lease operating expense (of which, credits of $79 million and $121 million were recorded during the three and nine months ended September 30, 2006, respectively) for amounts attributable to all other hurricane repair and cleanup related coverage. For the three and nine months ended September 30, 2006, our credit to lease operating expense exceeded our costs incurred to date for hurricane related repair and cleanup costs by approximately $34 million. We have reflected the cash flows related to the settlement of the property damage portion of our policies as a source of investing cash flows while the cash related to the settlement of our business interruption policy and other control of well/operator's extra expense policies has been reflected as a source of operating cash flows in our consolidated statement of cash flows. All remaining costs expected to be incurred in future periods related to the hurricanes will be accounted for based on the nature of the cost (i.e. capitalized to the extent related to field redevelopment, expensed to the extent related to repair or debris removal).

Inventories

Inventories consist primarily of tubular goods and well equipment held for use in our oil and gas operations and oil produced in offshore Malaysia and China but not sold. Inventories are carried at the lower of cost or market. Crude oil from our operations offshore Malaysia and China is produced into floating production, storage and off-loading vessels and sold periodically as barge quantities are accumulated. The product inventory at September 30, 2006 consisted of approximately 220,000 barrels of crude oil valued at cost of $6 million. Cost for purposes of the carrying value of oil inventory is the sum 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. 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. The functional currency for all other foreign operations is the U.S. dollar. Gains and losses incurred on currency transactions in other than a country’s functional currency are recorded under the caption “Other income (expenses) - Other” on our consolidated statement of income.

Accounting for Asset Retirement Obligations

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

The change in our ARO for the nine months ended September 30, 2006 is set forth below (in millions):

Balance as of January 1, 2006	$ 260
Accretion expense	11
Additions	23
Settlements	(22)
Balance as of September 30, 2006	272
Less: Current portion	49
Long-term ARO	$ 223

6

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Stock-Based Compensation

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), “*Share-Based Payment*,” (SFAS No. 123 (R)) to account for stock-based compensation. 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 in their financial statements the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant or modification, will be recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and a lattice-based model for our performance and market-based restricted shares. Prior to the adoption of SFAS No. 123(R), we followed the intrinsic value method in accordance with APB 25 to account for stock-based compensation. Prior period financial statements have not been restated.

Historically, we have used and we anticipate continuing to use unissued shares of stock when stock options are exercised. At September 30, 2006, we had approximately 2.6 million additional shares available for issuance pursuant to our existing plans. Of the shares available at September 30, 2006, only 1.1 million could be granted as restricted shares. Grants of restricted shares under our 2004 Omnibus Stock Plan reduce the total number of shares available under that plan by two times the number of shares issued.

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

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

For the three and nine months ended September 30, 2006, we recorded stock-based compensation expense of $7 million (pre-tax) and $23 million (pre-tax), respectively, for all plans. Of these amounts, $3 million and $10 million were capitalized in oil and gas properties for the three and nine months ended September 30, 2006, respectively. The impact to net income of adopting SFAS No. 123(R) for the three and nine months ended September 30, 2006 was $1 million, or $0.01 per basic and diluted share and $4 million, or $0.03 per basic and diluted share, respectively. SFAS No. 123(R) also requires tax benefits relating to excess stock-based compensation deductions to be prospectively presented in our statement of cash flows as financing cash inflows. Accordingly, for the nine months ended September 30, 2006, we reported $3 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

As of September 30, 2006, there was approximately $64 million of total unrecognized compensation expense related to unvested stock-based compensation. This compensation expense is expected to be recognized on a straight-line basis over the remaining vesting period of approximately five years.

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

The fair value of the stock options granted prior to and remaining outstanding at January 1, 2006 was determined using the Black-Scholes option valuation method assuming: no dividends, a weighted average risk-free interest rate of 4.09%, expected life of 6.5 years and a weighted average volatility of 37.52%.

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Information about stock option activity for the nine months ended September 30, 2006 is presented below:

	Number of Shares Underlying Options (In millions)	Weighted Average Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share	Weighted Average Contractual Life in Years	Aggregate Intrinsic Value (In millions) (1)
Outstanding at December 31, 2005	6.5	$23.60	$10.64	7.4	$171
Granted		—			
Exercised	(0.4)	20.87	9.30		(9)
Forfeited	(0.2)	27.98	12.76		(3)
Outstanding at September 30, 2006	5.9	$23.60	$10.67	6.6	$ 88
Exercisable at September 30, 2006	2.8	$19.67	$ 8.87	5.4	$ 52

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

The aggregate intrinsic value of stock options exercised during the three and nine months ended September 30, 2005 was approximately $13 million and $41 million, respectively.

Information about stock options outstanding and exercisable at September 30, 2006 is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Underlying Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Underlying Options	Weighted Average Exercise Price
$7.97 to $10.00	44,000	1.9 years	$ 8.14	44,000	$ 8.14
10.01 to 12.50	130,442	1.5 years	11.79	130,442	11.79
12.51 to 15.00	484,075	3.4 years	14.71	469,475	14.72
15.01 to 17.50	1,212,020	5.8 years	16.63	768,720	16.63
17.51 to 22.50	956,660	5.5 years	18.94	625,380	18.99
22.51 to 27.50	921,780	7.4 years	24.75	300,900	24.72
27.51 to 35.00	1,704,600	8.2 years	31.11	353,800	30.78

35.01 to 41.72	388,800	8.6 years	37.92	64,000	38.31
	5,842,377	6.6 years	$23.60	2,756,717	$19.67

Restricted Shares. At September 30, 2006, our employees held 0.6 million restricted shares that primarily vest equally over the service period of five years. The vesting of these shares is dependant upon the employees continued service with our company.

At September 30, 2006, 1.6 million restricted shares subject to performance-based vesting criteria (substantially all of which are considered market-based restricted shares under SFAS No. 123(R)) were outstanding. In February 2006, 974,000 restricted performance-based shares were granted to employees. The number of shares that vests is based upon established performance targets that will be assessed on March 1, 2009. The grant date fair value of these shares was $23.20 per share for a total value of $23 million. The expense will be recognized ratably over the service period from February 2006 to March 2009. Under the grants to our executive officers, they are permitted to retire on or after March 1, 2008, if certain other conditions are met, without forfeiting the shares granted. To the extent that our executive officers qualify for retirement based upon this provision, the expense will be recognized ratably over the service period from February 2006 to the applicable retirement eligibility date. Substantially all of the remaining performance-based 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 the targets identified in the respective restricted share agreements.

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Under our non-employee director restricted stock plan, immediately after each annual meeting of our stockholders, each of our nonemployee directors then in office receives a number of restricted shares determined by dividing $75,000 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 receive a number of restricted shares determined by dividing $75,000 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 September 30, 2006, 109,913 shares remained available for grants under the plan.

Information about the restricted shares granted during the nine months ended September 30, 2006 and the change in the number of outstanding restricted shares during that period is presented below:

	Service-Based	Performance/ Market-Based	Total
	(In thousands, except per share data)		
Non-vested shares outstanding at December 31, 2005	549	801	1,350
Granted	117	974	1,091
Forfeited	(22)	(25)	(47)
Vested	(48)	(169)	(217)
Non-vested shares outstanding at September 30, 2006	596	1,581	2,177
Weighted average grant date fair value of shares granted during the period	$44.48	$23.20	$25.52
Total fair value of shares vesting during the period	$ 943	$2,821	$3,764

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

During 2006, options to purchase 51,046 shares of our common stock at a weighted average fair value of $13.34 per share were issued under the plan. The fair value of the options granted since January 1, 2006 was determined using the Black-Scholes option valuation method assuming: no dividends, a risk-free weighted-average interest rate of 4.83%, expected life of 6 months and weighted-average volatility of 40.02%. At September 30, 2006, 686,501 shares of our common stock remained available for issuance pursuant to the plan.

U.K. Bonus Plan. We have a cash bonus plan for the employees of our U.K. North Sea operations. The value of the bonus is determined based on the value of the shares of our U.K. subsidiary as determined by our Board of Directors. This plan is accounted for as a liability plan under SFAS No. 123(R) and is not material to our financial statements.

Pro forma Disclosures. Prior to January 1, 2006, we accounted for our employee stock-based compensation using the intrinsic value method prescribed by APB 25. As required by SFAS No. 123(R), we have disclosed below the effect on net income and earnings per share that would have been recorded using the fair value based method for the three and nine months ended September 30, 2005. The weighted average fair value of the options granted in the first nine months of 2005 was determined using the Black-Scholes option valuation method assuming: no dividends, a weighted average risk-free interest rate of 3.87%, expected life of 6.5 years and weighted average volatility of 37.50%.

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
	(In millions, except per share data)	
Net income:		
As reported [1]	$	$ 164
Pro forma [2]	(3)	157
Basic earnings per common share —		
As reported	$	$1.31
Pro forma	(0.02)	1.25
Diluted earnings per common share —		
As reported	$	$1.29
Pro forma	(0.02)	1.23

______

(1) Includes stock-based compensation costs (net of related tax effects) of $1 million for the three months ended September 30, 2005 and $3 million for the nine months ended September 30, 2005.

(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 $4 million for the three months ended September 30, 2005 and $10 million for the nine months ended September 30, 2005.

New Accounting Developments

In July 2006, the FASB issued FASB Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes - an interpretation of FAS 109*" (Interpretation No. 48). Interpretation No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken in a tax return. It also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. Interpretation No. 48 is effective for fiscal years beginning after December 15, 2006. Earlier application is encouraged if the company has not yet issued financial statements, including interim financial statements, in the period Interpretation No. 48 is adopted. We are reviewing the interpretation and analyzing the potential impact, if any, of this new guidance.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)." SFAS No. 158 requires recognition of the funded status of a benefit plan on the balance sheet and the recognition through other comprehensive income of gains, losses, prior service costs and credits, net of tax, arising during the period but not included as a component of periodic benefit cost. In addition, the measurement date of plan assets and obligations must be as of the balance sheet date. Additional disclosures in the notes to the financial statements will also be required and guidance is prescribed regarding the selection of discount rates to be used in measuring the benefit obligation. The effective date of SFAS No. 158 is as of the end of the fiscal year ending after December 15, 2006. We do not believe that our financial position, results of operations or cash flows will be significantly impacted by SFAS No. 158.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted average number of shares of common stock (other than unvested restricted shares) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted shares (using the treasury stock method).

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

The following is the calculation of basic and diluted weighted average shares outstanding and EPS for the indicated periods:

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In millions, except per share data)			
Income (numerator):				
Net income — basic	$ 266	$	$ 509	$ 164
Net income — diluted	$ 266	$	$ 509	$ 164
Weighted average shares (denominator):				
Weighted average shares — basic	126	126	127	125
Dilution effect of stock options and unvested restricted shares outstanding at end of period	3		2	3
Weighted average shares — diluted	129	126	129	128
Earnings per share:				
Basic	$ 2.10	$	$ 4.02	$ 1.31
Diluted	$ 2.06	$	$ 3.95	$ 1.29

The calculation of shares outstanding for diluted EPS does not include the effect of outstanding stock options to purchase 0.2 million shares for the nine months ended September 30, 2005 because to do so would have been antidilutive. There were no antidilutive shares for the three months ended September 30, 2005 and the three and nine months ended September 30, 2006.

3. Oil and Gas Assets:

Oil and Gas Properties

Oil and gas properties consisted of the following at:

	September 30, 2006	December 31, 2005
	(In millions)	
Subject to amortization	$ 7,327	$ 6,141
Not subject to amortization:		
Exploration wells in progress	74	56
Development wells in progress	138	107
Capitalized interest	89	71
Fee mineral interests	23	23
Other capital costs:		
Incurred in 2006	88	—
Incurred in 2005	102	110

Incurred in 2004		393		413
Incurred in 2003 and prior		92		121
Total not subject to amortization		999		901
Gross oil and gas properties		8,326		7,042
Accumulated depreciation, depletion and amortization		(3,054)		(2,632)
Net oil and gas properties	$	5,272	$	4,410

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. Because of its size, evaluation of the Monument Butte Field in its entirety will take significantly longer than four years. At September 30, 2006 and December 31, 2005, $307 million and $316 million, respectively, of costs associated with the Monument Butte Field were not subject to amortization.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

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

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 as adjusted for location and quality differences and 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.

If net capitalized costs of oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. A ceiling test writedown is a charge to earnings. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower depreciation, depletion and amortization expense in future periods.

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil and gas prices decrease significantly or if we have substantial downward revisions in our estimated proved reserves. At September 30, 2006, the ceiling value of our reserves was calculated based upon quoted market prices of $4.18 per MMBtu for gas and $62.82 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties would have exceeded the ceiling amount by approximately $180 million (net of tax) at September 30, 2006. Cash flow hedges of oil and gas production in place at September 30, 2006 decreased the calculated ceiling value by approximately $10 million (net of tax). However, subsequent to quarter end, the market price for gas (Gas Daily – Henry Hub) increased to $7.92 per MMBtu and the price for oil (Platt's – WTI at Cushing) decreased to $60.18 per barrel on October 27, 2006, and utilizing these prices, the unamortized costs of our oil and gas properties would not have exceeded the ceiling amount. As a result, we did not record a writedown in the third quarter of 2006. The ceiling value calculated using the October 27, 2006 prices includes approximately $11 million (net of tax) related to the negative effects of future cash flow hedges of oil and gas production.

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

U.K. Southern Gas Basin - Sale Agreement

In September 2006, we, through our wholly owned subsidiary, Newfield Petroleum U.K. Limited, announced a sales agreement with Sojitz Energy Project Limited, a wholly owned subsidiary of Sojitz Corporation, relating to our Southern Gas Basin exploration and development program. The proceeds from this sale were $30 million and have been recorded as an adjustment to our U.K. cost center.

Under the agreement, Sojitz will participate in the ongoing development of our Grove Field and earn an interest in our West Cutter Prospect, the Seven Seas Discovery and two wells planned in the West Sole Area under our existing Exploration and Development Agreement with BP Exploration Operating Company Limited by participating in our 2007 exploration and appraisal drilling program.

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

4. Debt:

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

	September 30, 2006	December 31, 2005
	(In millions)	
Senior unsecured debt:		
Bank revolving credit facility:		
Prime rate based loans	$ —	$ —
LIBOR based loans	—	—
Total bank revolving credit facility	—	—
7.45% Senior Notes due 2007	125	125
Fair value of interest rate swaps [1]	(2)	(2)
7 5/8% Senior Notes due 2011	175	175
Fair value of interest rate swaps [1]	(2)	(2)
Total senior unsecured notes	296	296
Total senior unsecured debt	296	296
8 3/8% Senior Subordinated Notes due 2012	—	249
6 5/8% Senior Subordinated Notes due 2014	325	325
6 5/8% Senior Subordinated Notes due 2016	550	—
Total long-term debt	$ 1,171	$ 870

(1) We have hedged $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 7 5/8% Senior Notes due 2011. The hedges provide for us to pay variable and receive fixed interest payments.

Senior Subordinated Notes

On April 13, 2006, we sold $550 million principal amount of our 6 5/8% Senior Subordinated Notes due 2016. The notes are unsecured senior subordinated obligations that rank junior in right of payment to all of our present and future senior indebtedness, equally in right of payment to our outstanding 6 5/8% Senior Subordinated Notes due 2014, and senior to all of our future indebtedness that is expressly subordinated to the notes. We may redeem some or all of the notes at any time on or after April 15, 2011 at a redemption price stated in the indenture governing the notes. Prior to April 15, 2011, we may redeem all, but not part, of the notes at a redemption price based on a makewhole amount plus accrued and unpaid interest to the date of redemption. In addition, before April 15, 2009, we may redeem up to 35% of the original principal amount of the notes with the net cash proceeds of certain sales of our common stock at 106.625% of the principal amount plus accrued and unpaid interest to the date of redemption. Like the indenture governing our other senior subordinated notes, these notes may limit our ability under certain circumstances to 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.

On May 3, 2006, we redeemed all $250 million principal amount of our 8 3/8% Senior Subordinated Notes due 2012. The redemption included a premium related to the early extinguishment of the notes of $19 million. This premium and the remaining unamortized original issuance costs of the notes of $8 million were recorded as an expense under the caption “Operating expenses - Other” on our consolidated statement of income.

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Credit Arrangements

In December 2005, we entered into a revolving credit facility that matures in December 2010. The terms of our credit facility provide for initial loan commitments of $1 billion from a syndicate of 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 our credit facility. Loans under the credit facility bear interest, at our option, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate substantially equal to the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (100 basis points per annum at September 30, 2006). At September 30, 2006, we had no borrowings under our credit facility.

The credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0; maintenance of a ratio of total debt to earnings before gain or loss on the disposition of assets, interest expense, income taxes, depreciation, depletion and amortization expense, exploration and abandonment expense and other noncash charges and expenses to consolidated interest expense of at least 3.5 to 1.0; and as long as our debt rating is below investment grade, the maintenance of an annual ratio of the calculated net present value of our oil and gas properties to total debt of at least 1.75 to 1.00.

As of September 30, 2006, we had $58 million of undrawn letters of credit under our credit facility. We also have a total of $110 million of borrowing capacity under money market lines of credit with various banks. At September 30, 2006, we had no borrowings under our money market lines.

5. Commitments and Contingencies:

Lease Commitments

We have various commitments under non-cancellable operating lease agreements for office space, equipment and drilling rigs. The majority of these commitments are related to multi-year contracts for drilling rigs. Future minimum payments required under our operating leases as of September 30, 2006 are as follows (in millions):

2006	$ 18
2007	49
2008	38
2009	14
2010	4
Thereafter	18
Total minimum lease payments	$ 141

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 September 30, 2006, these work related commitments totaled $364 million and were comprised of $256 million in the United States and $108 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 that these matters will 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)
(Unaudited)

6. 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 three and nine months ended September 30, 2006 and 2005. 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)			
Three Months Ended September 30, 2006:						
Oil and gas revenues	$ 410	$ —	$ 13	$ 2	$ —	$ 425
Operating expenses:						
Lease operating	33	—	3	—	—	36
Production and other taxes	10	—	2	—	—	12
Depreciation, depletion and amortization	156	—	2	1	—	159
Ceiling test writedown	—	—	—	—	6	6
General and administrative	31	1	2	—	—	34
Other	(6)	—	—	—	—	(6)
Allocated income taxes	67	—	2	—	—	
Net income (loss) from oil and gas properties	$ 119	$ (1)	$ 2	$ 1	$ (6)	
Total operating expenses						241
Income from operations						184
Interest expense, net of interest income, capitalized interest and other						(10)
Commodity derivative income						247
Income before income taxes						$ 421
Total long-lived assets	$ 4,891	$ 182	$ 134	$ 64	$ 1	$ 5,272

Additions to long-lived assets	$	404	$	65	$	19	$	7	$	—	$	495

15

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Three Months Ended September 30, 2005:						
Oil and gas revenues	$ 441	$ —	$ 19	$ —	$ —	$ 460
Operating expenses:						
Lease operating	51	—	4	—	—	55
Production and other taxes	16	—	2	—	—	18
Depreciation, depletion and amortization	125	—	2	—	—	127
General and administrative	25	—	—	—	—	25
Other	(7)	—	—	—	—	(7)
Allocated income taxes	88	—	4	—	—	
Net income from oil and gas properties	$ 143	$ —	$ 7	$ —	$ —	
Total operating expenses						218
Income from operations						242
Interest expense, net of interest income, capitalized interest and other						(4)
Commodity derivative expense						(238)
Income before income taxes						$ —
Total long-lived assets	$ 3,997	$ 44	$ 76	$ 38	$ 15	$ 4,170
Additions to long-lived assets	$ 258	$ 8	$ 14	$ —	$ 2	$ 282

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Nine Months Ended September 30, 2006:						
Oil and gas revenues	$ 1,208	$ —	$ 36	$ 2	$ —	$ 1,246
Operating expenses:						
Lease operating	146	—	9	—	—	155

Production and other taxes	35	—	8	—	—	43
Depreciation, depletion and amortization	427	—	6	1	—	434
Ceiling test writedown	—	—	—	—	6	6
General and administrative	85	4	2	1	—	92
Other	(11)	—	—	—	—	(11)
Allocated income taxes	189	(2)	4	—	—	
Net income (loss) from oil and gas properties	$ 337	$ (2)	$ 7	$ —	$ (6)	
Total operating expenses						719
Income from operations						527
Interest expense, net of interest income, capitalized interest and other						(25)
Commodity derivative income						299
Income before income taxes						$ 801
Total long-lived assets	$ 4,891	$ 182	$ 134	$ 64	$ 1	$ 5,272
Additions to long-lived assets	$ 1,130	$ 143	$ 54	$ 20	$ 1	$ 1,348

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Nine Months Ended September 30, 2005:						
Oil and gas revenues	$ 1,275	$ 1	$ 43	$ —	$ —	$ 1,319
Operating expenses:						
Lease operating	140	—	10	—	—	150
Production and other taxes	37	—	4	—	—	41
Depreciation, depletion and amortization	397	—	6	—	—	403
General and administrative	74	2	—	—	—	76
Other	(7)	—	—	—	—	(7)
Allocated income taxes	221	(1)	8	—	—	
Net income from oil and gas properties	$ 413	$ —	$ 15	$ —	$ —	
Total operating expenses						663
Income from operations						656
Interest expense, net of interest income, capitalized interest and other						(17)
Commodity derivative expense						(393)
Income before income taxes						$ 246
Total long-lived assets	$ 3,997	$ 44	$ 76	$ 38	$ 15	$ 4,170
Additions to long-lived assets	$ 738	$ 31	$ 26	$ 1	$ 3	$ 799

7. 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 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.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

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. All open contracts that were designated and qualified as cash flow hedges as of September 30, 2005 will continue to be accounted for under hedge accounting until the contract expires or is otherwise settled. After-tax changes in the fair value of a derivative that is highly effective and qualifies and is designated 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. Settlements of our derivatives designated as cash flow hedges are included in operating cash flows on our consolidated statement of cash flows. At September 30, 2006, we had a net $16 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 $18 million to be sold within the next 12 months and hedged production associated with a remaining net gain of approximately $2 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 of September 30, 2006, we had entered into contracts that qualify and were designated as cash flow hedges with respect to our future production as follows:

Natural Gas

	Estimated

Period and Type of Contract	Volume in MMMBtus	NYMEX Contract Price Per MMBtu Floor Contracts Range	Weighted Average	Fair Value Asset (Liability) (In millions)
October 2006 - December 2006				
Floor contracts	1,600	$7.35	$7.35	$ 5
				$ 5

18

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Oil

		NYMEX Contract Price Per Bbl					Estimated Fair Value Asset
			Collars				
		Swaps	Floors		Ceilings		
Period and Type of Contract	**Volume in MBbls**	**(Weighted Average)**	**Range**	**Weighted Average**	**Range**	**Weighted Average**	**(Liability) (In millions)**
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	—	—	—	—	(12)
Collar contracts	365	—	50.00 - 55.00	52.50	77.10 - 83.25	80.18	—
							$ (25)

Other Derivative Contracts

Beginning in the fourth quarter of 2005 we elected not to designate any additional swap, collar and floor contracts that were entered into subsequent to October 1, 2005 as accounting hedges under SFAS No. 133. These contracts and our basis contracts, as well as our three-way collar contracts, which do not qualify 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 income (expense).” Settlements of such derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

As of September 30, 2006, we had entered into contracts with respect to our future production that are not accounted for as hedges as set forth in the tables below.

Natural Gas

	NYMEX Contract Price Per MMBtu					Estimated Fair Value Asset
			Collars			
	Swaps	Floors		Ceilings		

Period and Type of Contract	**Volume in MMMBtus**	**(Weighted Average)**	**Range**	**Weighted Average**	**Range**	**Weighted Average**	**(Liability) (In millions)**
October 2006 - December 2006							
Price swap contracts	13,810	$9.16	—	—	—	—	$ 41
Collar contracts	16,490	—	$9.00 - $9.50	$9.16	$11.00 - $15.40	$12.74	47
January 2007 - December 2007							
Price swap contracts	62,730	9.07	—	—	—	—	99
Collar contracts	55,720	—	6.50 - 10.00	8.09	8.23 - 15.75	11.09	55
							$ 242

19

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Oil

Period and Type of Contract	Volume in MBbls	Swaps (Weighted Average)	Additional Put Range	Additional Put Weighted Average	Collars Floors Range	Collars Floors Weighted Average	Collars Ceilings Range	Collars Ceilings Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
October 2006 - December 2006									
Price swap contracts	30	$70.00	—	—	—	—	—	—	$ —
Collar contracts	60	—	—	—	$60.00	$60.00	$80.50 - $81.00	$80.75	—
3-Way collar contracts	480	—	$30.00 - $50.00	$37.43	35.00 - 60.00	44.69	50.50 - 80.00	62.21	(3)
January 2007 - December 2007									
Price swap contracts	120	70.00	—	—	—	—	—	—	—
Collar contracts	240	—	—	—	60.00	60.00	80.50 - 81.00	80.75	(4)
3-Way collar contracts	3,525	—	25.00 - 50.00	30.02	32.00 - 60.00	37.12	44.70 - 82.00	55.32	(48)
January 2008 - December 2008									
3-Way collar contracts	3,294	—	25.00 - 29.00	26.56	32.00 - 35.00	33.00	49.50 - 52.90	50.29	(59)
January 2009 - December 2009									
3-Way collar contracts	3,285	—	25.00 - 30.00	27.00	32.00 - 36.00	33.33	50.00 - 54.55	50.62	(55)
January 2010 - December 2010									
	3,645	—		28.60		34.90		51.52	(54)

3-Way collar contracts	25.00 - 32.00	32.00 - 38.00	50.00 - 53.50	
				$ (223)

Basis Contracts

We have entered into natural gas basis hedges to lock in the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points as set forth in the table below.

	Onshore Gulf Coast	Offshore Gulf of Mexico	Mid-Continent	Rocky Mountains
October 2006 - December 2006				
Volume in MMMBtus	12,285	800	5,520	300
Weighted average differential	($0.78)	$0.21	($1.23)	($1.83)

Commodity Derivative Income (Expense)

The following table presents information about the components of commodity derivative income (expense) for the three and nine months ended September 30, 2006 and 2005.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In millions)			
Cash flow hedges:				
Hedge ineffectiveness	$ (1)	$ (14)	$ 5	$ (20)
Other derivative contracts:				
Unrealized (loss) on discontinued cash flow hedges	—	(65)	—	(65)
Realized (loss) on settlement of discontinued cash flow hedges	—	(24)	—	(24)
Unrealized gain (loss) due to changes in fair market value	210	(125)	221	(271)
Realized gain (loss) on settlement	38	(10)	73	(13)
Total commodity derivative income (expense)	$ 247	$ (238)	$ 299	$ (393)

As a result of the production deferrals experienced in the Gulf of Mexico related to Hurricanes Katrina and Rita, hedge accounting was discontinued during the third quarter of 2005 on a portion of our derivative 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. The $65 million unrealized loss on discontinued cash flow hedges recorded during 2005 represents the mark-to-market adjustments previously deferred to “Accumulated other comprehensive income (loss) - Commodity derivatives” on our consolidated balance sheet.

Table of Contents

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

8. Accrued Liabilities:

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

	September 30, 2006	December 31, 2005
	(In millions)	
Revenue payable	$ 98	$ 117
Accrued capital costs	261	154
Accrued lease operating expense	41	33
Employee incentive expense	68	60
Accrued interest on notes	25	21
Taxes payable	34	26
Deferred acquisition payments	9	20
Other	51	23
Total accrued liabilities	$ 587	$ 454

9. Comprehensive Income:

For the periods indicated, our comprehensive income (loss) consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In millions)			
Net income	$ 266	$ —	$ 509	$ 164
Foreign currency translation adjustment, net of tax of $1 for the three months ended September 30, 2006, and ($5) and $2 for the nine months ended September 30, 2006 and 2005, respectively	2	(1)	9	(5)
Reclassification adjustments for settled hedging positions, net of tax of $3 and $7 for the three months ended September 30, 2006 and 2005, respectively, and $15 and $18 for the nine months ended September 30, 2006 and 2005, respectively	(6)	(14)	(28)	(33)
Reclassification adjustments for discontinued cash flow hedges, net of tax of $23 for the three and nine months ended September 30, 2005 (1)	—	(42)	—	(42)
	28	5	52	(42)

Changes in fair value of outstanding hedging positions, net of tax of ($15) and ($3) for the three months ended September 30, 2006 and 2005, respectively, and ($28) and $23 for the nine months ended September 30, 2006 and 2005, respectively								
Total comprehensive income (loss)	$	290	$	(52)	$	542	$	42

(1) During the third quarter of 2005, as a result of the production deferrals experienced in the Gulf of Mexico related to Hurricanes Katrina and Rita, hedge accounting was discontinued on a portion of our derivative 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.

Table of Contents

Item 2. 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.

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

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 as adjusted for location and quality differences and 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.

If net capitalized costs of oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. A ceiling test writedown is a charge to earnings. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower depreciation, depletion and amortization expense in future periods.

Table of Contents

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil and gas prices decrease significantly or if we have substantial downward revisions in our estimated proved reserves. At September 30, 2006, the ceiling value of our reserves was calculated based upon quoted market prices of $4.18 per MMBtu for gas and $62.82 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties would have exceeded the ceiling amount by approximately $180 million (net of tax) at September 30, 2006. Cash flow hedges of oil and gas production in place at September 30, 2006 decreased the calculated ceiling value by approximately $10 million (net of tax). However, subsequent to quarter end, the market price for gas (Gas Daily – Henry Hub) increased to $7.92 per MMBtu and the price for oil (Platt's – WTI at Cushing) decreased to $60.18 per barrel on October 27, 2006, and utilizing these prices, the unamortized costs of our oil and gas properties would not have exceeded the ceiling amount. As a result, we did not record a writedown in the third quarter of 2006. The ceiling value calculated using the October 27, 2006 prices includes approximately $11 million (net of tax) related to the negative effects of future cash flow hedges of oil and gas production. Decreases in market prices from October 27, 2006 levels, as well as changes in production rates, levels of reserves, the evaluation of cost excluded from amortization, future development costs and service costs could result in future ceiling test writedowns.

Reserve Replacement. Most of our producing properties have declining production rates. As a result, to maintain and grow our production and cash flow we must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and acquire oil and gas reserves.

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

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

Other factors. Please see “*Risk Factors*” in Item 1A of our annual report on Form 10-K for the year ended December 31, 2005 for a more detailed discussion of a number of other factors that affect our business, financial condition and results of operations. This report should be read together with those discussions.

Table of Contents

Results of Operations

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 derivative contracts associated with our production that are accounted for as hedges. Settlement of derivative contracts that are not accounted for as hedges has no effect on our reported revenues. Please see Note 7, "Commodity Derivative Instruments and Hedging Activities," to our consolidated financial statements appearing earlier in this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Our revenues may vary significantly from period to period as a result of changes in commodity prices or volumes of production sold. Revenues for the third quarter of 2006 were 8% lower than the comparable period of 2005 due to lower gas prices and lower reported oil production relating to the timing of liftings in Malaysia, offset by slightly higher oil prices and gas production. Revenues for the first nine months of 2006 were 6% lower than the same period of the prior year due to production deferrals related to Hurricanes Katrina and Rita, the timing of liftings from our Monument Butte field due to limited refining capacity for such production during the first half of 2006 and the timing of liftings in Malaysia, offset by higher oil prices.

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Percentage Increase (Decrease)	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Percentage Increase (Decrease)
Production [1]:						
United States:						
Natural gas (Bcf)	51.2	46.8	9%	143.6	151.3	(5%)
Oil and condensate (MBbls)	1,674	1,769	(5%)	4,609	5,853	(21%)
Total (Bcfe)	61.2	57.4	7%	171.2	186.4	(8%)
International:						
Natural gas (Bcf)	—	—	0%	—	0.1	(100%)
Oil and condensate (MBbls)	225	298	(24%)	593	806	(26%)
Total (Bcfe)	1.4	1.8	(22%)	3.6	5.0	(28%)
Total:						
Natural gas (Bcf)	51.2	46.8	9%	143.6	151.4	(5%)
Oil and condensate (MBbls)	1,899	2,067	(8%)	5,202	6,659	(22%)
Total (Bcfe)	62.6	59.2	6%	174.8	191.4	(9%)
Average Realized Prices [2]:						
United States:						
Natural gas (per Mcf)	$ 6.21	$ 7.60	(18%)	$ 6.68	$ 6.72	(1%)
Oil and condensate (per Bbl)	54.21	47.73	14%	53.22	43.78	22%
Natural gas equivalent (per Mcfe)	6.67	7.67	(13%)	7.03	6.83	3%
International:						
Natural gas (per Mcf)	$ —	$ —	0%	$ —	$ 4.87	(100%)
Oil and condensate (per Bbl)	66.75	62.27	7%	64.80	53.45	21%
Natural gas equivalent (per Mcfe)	11.12	10.36	7%	10.80	8.80	23%
Total:						
Natural gas (per Mcf)	$ 6.21	$ 7.60	(18%)	$ 6.68	$ 6.71	—
Oil and condensate (per Bbl)	55.70	49.83	12%	54.54	44.95	21%
Natural gas equivalent (per Mcfe)	6.77	7.75	(13%)	7.11	6.88	3%

(1) Represent volumes sold regardless of when produced.

(2) Average realized prices include the effects of hedging other than contracts that are not designated for hedge accounting. Had we included the effect of these contracts, our average realized price for total gas would have been $7.06 per Mcf and $6.97 per Mcf for the third quarter of 2006 and 2005, respectively, and $7.27 per Mcf and $6.52 per Mcf for the nine months ended September 30, 2006 and 2005, respectively. Our total oil and condensate average realized price would have been $52.95 per Bbl and $47.83 per Bbl for the third quarter of 2006 and 2005, respectively, and $52.19 per Bbl and $43.84 per Bbl for the nine months ended September 30, 2006 and 2005, respectively. Without the effects of hedging, our average realized prices for the third quarter of 2006 and 2005 would have been $6.19 per Mcf and $7.95 per Mcf, respectively, for gas and $64.18 per barrel and $59.82 per barrel, respectively, for oil. Our average prices, without the effects of hedging, for the nine months ended September 30, 2006 and 2005 would have been $6.63 per Mcf and $6.82 per Mcf, respectively, for gas and $62.69 per barrel and $52.18 per barrel, respectively, for oil

Table of Contents

Production. Our total oil and gas production (stated on a natural gas equivalent basis) for the third quarter of 2006 increased 6% and for the nine months ended September 30, 2006 decreased 9% over the comparable period of 2005. The third quarter 2006 increase was primarily due to successful drilling efforts in the Mid-Continent. The year-to-date 2006 decrease was primarily the result of Gulf of Mexico production deferrals related to the 2005 hurricanes, natural field declines, the timing of liftings from our Monument Butte field due to limited refining capacity for such production and the timing of liftings in Malaysia. The decrease was partially offset by successful drilling efforts in the Mid-Continent.

Natural Gas. Our third quarter and first nine months of 2006 natural gas production increased 9% and decreased 5%, respectively, when compared to the same periods of 2005. The third quarter 2006 increase was primarily due to successful drilling efforts in the Mid-Continent and Rocky Mountain areas. The year-to-date decrease was primarily the result of Gulf of Mexico production deferrals related to the 2005 hurricanes.

Crude Oil and Condensate. Our third quarter and first nine months of 2006 oil and condensate production decreased 8% and 22%, respectively, when compared to the same periods of 2005. The third quarter of 2006 decrease was primarily due to the timing of liftings in Malaysia. The year-to-date decrease was the result of production deferrals related to the 2005 hurricanes, the timing of liftings from our Monument Butte field due to limited refining capacity for such production and the timing of liftings in Malaysia.

Operating Expenses. Generally, our proved reserves and production have grown steadily since our founding. As a result, our operating expenses also have increased. We believe the most informative way to analyze changes in operating expenses from period to period is on a unit-of-production, or per Mcfe, basis.

The following table presents information about our operating expenses for the third quarter of 2006 and 2005.

	Unit-of-Production (Per Mcfe)			Amount (In millions)		
	Three Months Ended September 30,		Percentage Increase (Decrease)	Three Months Ended September 30,		Percentage Increase (Decrease)
	2006	2005		2006	2005	
United States:						
Lease operating	$ 0.54	$ 0.88	(39%)	$ 33	$ 51	(34%)
Production and other taxes	0.14	0.28	(50%)	10	16	(46%)
Depreciation, depletion and amortization	2.55	2.17	18%	156	125	26%
General and administrative	0.51	0.43	19%	31	25	25%
Other	(0.09)	(0.12)	(25%)	(6)	(7)	(23%)
Total operating expenses	$ 3.65	$ 3.64	—	$ 224	$ 210	7%
International:						
Lease operating	$ 2.23	$ 2.18	2%	$ 3	$ 4	(23%)
Production and other taxes	1.78	0.99	80%	2	2	36%
Depreciation, depletion and amortization	1.89	1.26	50%	3	2	14%
Ceiling test writedown	4.60	—	100%	6	—	100%
General and administrative	2.54	0.35	626%	3	—	450%
Total operating expenses	$ 13.04	$ 4.78	173%	$ 17	$ 8	106%
Total:						
Lease operating	$ 0.58	$ 0.92	(37%)	$ 36	$ 55	(34%)

Production and other taxes	0.18	0.30	(40%)	12	18	(38%)
Depreciation, depletion and amortization	2.54	2.14	19%	159	127	25%
Ceiling test writedown	0.10	—	100%	6	—	100%
General and administrative	0.55	0.43	28%	34	25	35%
Other	(0.09)	(0.12)	(25%)	(6)	(7)	(23%)
Total operating expenses	$ 3.86	$ 3.67	5%	$ 241	$ 218	11%

Domestic Operations. While our domestic operating expenses for the third quarter of 2006, stated on an Mcfe basis, remained flat period over period, the components of domestic operating expenses changed significantly over the same period. These changes are discussed below.

- Lease operating expense (LOE), on an Mcfe basis, decreased significantly due to a $0.55 per Mcfe ($34 million) credit resulting from the difference between the proceeds received in the third quarter of 2006 from the settlement of all of our insurance claims related to Hurricanes Katrina and Rita and our hurricane related expenses incurred to date. Without the impact of the insurance settlement, our LOE, on an Mcfe basis, would have been $1.09 per Mcfe. In addition to our normal recurring expenses, our LOE in the fourth quarter of 2006 is expected to include approximately $40 million of continuing hurricane related expenses. The increase over the same period of 2005 was due to higher operating costs.

Table of Contents

- Production and other taxes, on an Mcfe basis, decreased primarily due to refunds related to production tax exemptions on certain of our onshore high cost gas wells.

- The increase in our depreciation, depletion and amortization (DD&A) rate 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 for the third quarter of 2006 and $0.06 per Mcfe for the third quarter of 2005. The component of DD&A associated with furniture, fixture and equipment was $0.02 per Mcfe for the third quarter of 2006 and 2005.

- General and administrative (G&A) expense, on an Mcfe basis, increased primarily due to increased stock-based compensation expense of approximately $0.07 per Mcfe due to the adoption of SFAS No. 123(R) on January 1, 2006. See Note 1, "Organization and Summary of Significant Accounting Policies—*Stock-Based Compensation,*" to our consolidated financial statements appearing earlier in this report. This increase was partially offset by a decrease in incentive compensation expense as a result of lower adjusted net income (as defined in our incentive compensation plan) in the third quarter of 2006 as compared to the prior year. Adjusted net income for purposes of our incentive compensation plan excludes unrealized gains and losses on commodity derivatives. We capitalized $10 million of direct internal costs in the third quarter of 2006 and 2005.

- In the third quarter of 2006, we recorded a $6 million benefit in "Operating expenses - Other" from our business interruption insurance coverage relating to operations disruptions caused by the 2005 hurricanes.

- In August 2005, we sold our interest in the floating production system and related equipment we acquired in the EEX transaction for net proceeds of $7 million. This gain is included in "Operating expenses – Other."

International Operations. Our international operating expenses for the third quarter of 2006, stated on an Mcfe basis, increased 173% over the same period of 2005 because:

- Production and other taxes increased as a result of significantly higher crude oil prices;

- The increase in our DD&A rate resulted from higher cost reserve additions in Malaysia and initial production and liftings from our operations in China during the third quarter of 2006.

- We recorded a ceiling test writedown of $6 million associated with the discontinuation of our operations in Brazil; and

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

The following table presents information about our operating expenses for the first nine months of 2006 and 2005.

	Unit-of-Production (Per Mcfe)			**Amount (In millions)**		
	Nine Months Ended September 30,		**Percentage Increase (Decrease)**	**Nine Months Ended September 30,**		**Percentage Increase (Decrease)**
	2006	**2005**		**2006**	**2005**	
United States:						
Lease operating	$ 0.85	$ 0.75	13%	$ 146	$ 140	4%
Production and other taxes	0.20	0.20	—	35	37	(8%)
Depreciation, depletion and amortization	2.50	2.13	17%	427	397	8%

General and administrative	0.50	0.40	25%	85	74	15%
Other	(0.06)	(0.04)	50%	(11)	(7)	44%
Total operating expenses	$ 3.99	$ 3.44	16%	$ 682	$ 641	7%
International:						
Lease operating	$ 2.68	$ 2.05	31%	$ 9	$ 10	(6%)
Production and other taxes	2.23	0.71	214%	8	4	126%
Depreciation, depletion and amortization	1.78	1.29	38%	7	6	1%
Ceiling test writedown	1.75	—	100%	6	—	100%
General and administrative	1.90	0.40	375%	7	2	241%
Total operating expenses	$ 10.34	$ 4.45	132%	$ 37	$ 22	67%
Total:						
Lease operating	$ 0.89	$ 0.78	14%	$ 155	$ 150	4%
Production and other taxes	0.24	0.21	14%	43	41	4%
Depreciation, depletion and amortization	2.48	2.11	18%	434	403	8%
Ceiling test writedown	0.04	—	100%	6	—	100%
General and administrative	0.53	0.40	33%	92	76	21%
Other	(0.06)	(0.04)	50%	(11)	(7)	44%
Total operating expenses	$ 4.12	$ 3.46	19%	$ 719	$ 663	9%

Table of Contents

Domestic Operations. Our domestic operating expenses for the first nine months of 2006, stated on an Mcfe basis, increased 16% over the same period of 2005. This increase was primarily related to the following items:

- LOE, on an Mcfe basis, was adversely impacted by lower production, higher operating costs and increased well workover activity. This increase was offset by a $0.20 per Mcfe ($34 million) credit resulting from the difference between the proceeds received in the third quarter of 2006 from the settlement of all of our insurance claims related to Hurricanes Katrina and Rita and our hurricane related expenses incurred to date. Without the impact of the insurance settlement, our LOE, on an Mcfe basis, would have been $1.05 per Mcfe.

- Production and other taxes, on an Mcfe basis, remained flat period over period. Production and other taxes decreased due to exemption refunds related to some of our onshore high cost gas wells. This decrease was offset by higher commodity prices and a 13% increase in the proportion of our production volumes subject to production taxes.

- The increase in our DD&A rate 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 for the first nine months of 2006 and $0.05 per Mcfe for the first nine months of 2005. The component of DD&A associated with furniture, fixture and equipment was $0.02 per Mcfe for the first nine months of 2006 and 2005.

- G&A expense, on an Mcfe basis, was adversely impacted by lower production. The increase of $0.10 per Mcfe, or 25%, was impacted by growth in our workforce and an increase in stock compensation expense of approximately $0.07 per Mcfe due to the adoption of SFAS No. 123(R). See Note 1, "Organization and Summary of Significant Accounting Policies—*Stock-Based Compensation.*" During the first nine months of 2006 and 2005, we capitalized $29 million of direct internal costs.

- In May 2006, we redeemed all $250 million of our 8 3/8% Senior Subordinated Notes due 2012. We recorded a charge for the $19 million early redemption premium we paid and a charge of $8 million for the remaining unamortized original issuance costs related to the notes. In the first nine months of 2006, we recorded a $36 million benefit from our business interruption insurance coverage relating to the operations disruptions caused by the 2005 hurricanes. Both of these items are included in "Operating expenses - Other."

- In August 2005, we sold our interest in the floating production system and related equipment we acquired in the EEX transaction for net proceeds of $7 million. This gain is included in "Operating expenses – Other."

International Operations. Our international operating expenses for the first nine months of 2006, stated on an Mcfe basis, increased 132% over the same period of 2005 because:

- Production and other taxes increased in response to significantly higher crude oil prices;

- The increase in our DD&A rate resulted from higher cost reserve additions in Malaysia and initial production and liftings from our operations in China during the third quarter of 2006.

- We recorded a ceiling test writedown of $6 million associated with the discontinuation of our operations in Brazil; and

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

Interest Expense. The following table presents information about our interest expense for the three and nine month periods ended September 30, 2005 and 2006.

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
	(In millions)			
Gross interest expense	$ 23	$ 17	$ 65	$ 54
Capitalized interest	(11)	(11)	(33)	(34)
Net interest expense	$ 12	$ 6	$ 32	$ 20

The increase in interest expense for the three and nine months ended September 30, 2006 resulted primarily from the issuance of $550 million principal amount of our 6 5/8% Senior Subordinated Notes due 2016 on April 3, 2006 partially offset by the redemption of all $250 million principal amount of our 8 3/8% Senior Subordinated Notes due 2012 on May 3, 2006.

Table of Contents

Commodity Derivative Income (Expense). The following table presents information about the components of commodity derivative income (expense) for the three and nine month periods ended September 30, 2005 and 2006.

	Three Months Ended September 30,		Nine Months Ended September 30	
	2006	2005	2006	2005
	(In millions)			
Cash flow hedges:				
Hedge ineffectiveness	$ (1)	$ (14)	$ 5	$ (20)
Other derivative contracts:				
Unrealized (loss) on discontinued cash flow hedges	—	(65)	—	(65)
Realized (loss) on settlement of discontinued cash flow hedges	—	(24)	—	(24)
Unrealized gain (loss) due to changes in fair market value	210	(125)	221	(271)
Realized gain (loss) on settlement	38	(10)	73	(13)
Total commodity derivative income (expense)	$ 247	$ (238)	$ 299	$ (393)

Hedge ineffectiveness is associated with our hedging contracts that are designated for hedge accounting under SFAS No. 133. As a result of the production deferrals experienced in the Gulf of Mexico related to Hurricanes Katrina and Rita, hedge accounting was discontinued during the third quarter of 2005 on a portion of our contracts that had previously qualified as effective cash flow hedges of our Gulf of Mexico production and other contracts were redesignated as hedges of our onshore Gulf Coast production. The $65 million unrealized loss on discontinued cash flow hedges recorded during 2005 represents the mark-to-market adjustments previously deferred to “Accumulated other comprehensive income (loss) - Commodity derivatives” on our consolidated balance sheet. The unrealized gain (loss) due to changes in fair market value is associated with our derivative contracts that are not designated for hedge accounting and represents changes in the fair value of our open contracts during the period.

Taxes. The effective tax rates for the third quarter of 2006 and 2005 were 36.8% and 35%, respectively. The effective tax rates for the first nine months of 2006 and 2005 were 36.5% and 33.3%, respectively. The effective tax rate for the first nine months of 2005 was less than the federal statutory rate because the $8 million valuation allowance on our U.K. net operating loss carryforwards was reversed following a substantial increase in estimated future taxable income as result of our Grove discovery in the U.K. North Sea. Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing and amount of future production and future operating expenses and capital costs.

Liquidity and Capital Resources

We must find new and develop existing reserves to maintain and grow our production and cash flow. We do this 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.

In August 2006, we reached an agreement with our underwriters to settle all claims related to Hurricanes Katrina and Rita (business interruption, property damage and control of well/operator’s extra expense) for $235 million, after adjustments for applicable deductibles and additional insureds' share of the settlement. After adjustments for applicable deductibles and amounts already received, we received $190 million in September 2006.

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 increased our capital budget during the year as a result of acquisitions or successful drilling. Because of the nature of the properties we own, a majority of our capital budget is discretionary. Our 2006 capital budget exceeds currently expected cash flow from operations by approximately $500 million. We will make up the shortfall with the remaining proceeds from our $550 million Senior Subordinated Notes offering (see — *Cash Flows from Financing Activities* below) and the insurance proceeds noted above.

Table of Contents

Credit Arrangements. In December 2005, we entered into a revolving credit facility that matures in December 2010. Our credit facility provides for initial total loan commitments of $1 billion from a syndication of participating banks, led by JPMorgan Chase as the agent bank. The loan commitments may be increased to a maximum aggregate amount of $1.5 billion if the current lenders increase their loan commitments or new financial institutions are added to the credit facility. Loans under our credit facility bear interest, at our option, based on (a) a rate per annum equal to the higher of prime rate or the weighted average of the rates on overnight federal funds transactions during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate, substantially equal to the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (100 basis points per annum at September 30, 2006). At October 30, 2006, we had no outstanding borrowings and $52 million of undrawn letters of credit outstanding under our credit facility.

Our credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0; maintenance of a ratio of total debt to earnings before gain or loss on the disposition of assets, interest expense, income taxes, 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 September 30, 2006, we were in compliance with all of our debt covenants.

We also have a total of $110 million of borrowing capacity under money market lines of credit with various banks. At October 30, 2006, we had no outstanding borrowings under our money market lines.

As of October 30, 2006, we had approximately $996 million of available borrowing capacity under our credit arrangements.

Redemption of 7.45% Senior Notes due 2007. On October 15, 2007, our 7.45% Senior Notes with an aggregate principal amount of $125 million become due. We are currently evaluating our options to fund the repayment.

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 positive working capital of $67 million as of September 30, 2006. This compares to a working capital deficit of $130 million as of December 31, 2005. Our current assets at September 30, 2006 include cash and short-term investments of $295 million that represent the remaining proceeds from our $550 million Senior Subordinated Note Offering in April 2006 and the proceeds from our third quarter 2006 hurricane insurance settlement. Our working capital is affected by fluctuations in the fair value of our commodity derivative instruments. As of September 30, 2006, our net short-term derivatives were a $171 million asset compared to a net short-term derivative liability of $89 million at December 31, 2005.

Cash Flows from Operations. Cash flows from operations are primarily affected by production and commodity prices, net of the effects of settlements of our derivative contracts. Our cash flows from operations also are impacted by changes in working capital. We sell substantially all of our natural gas and oil production under floating market contracts. However, we enter into commodity hedging arrangements to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flows. See “Oil and Gas Hedging” below. We typically receive the cash associated with accrued oil and gas sales within 45-60 days of production. As a result, cash flows from operations and income from operations generally correlate, but cash flows from operations is impacted by changes in working capital and is not affected by DD&A, writedowns or other non-cash charges.

Our net cash flow from operations was $1,145 million for the nine months ended September 30, 2006, a 29% increase over the same period of the prior year. The increase was primarily due to $190 million of operating cash flows related to our hurricane insurance settlement for business interruption, control of well and operator's extra expense.

Cash Flows from Investing Activities. During the nine months ended 2006, we began to invest the excess cash from our $550 million Senior Subordinated Notes offering. As a result, during the first nine months of 2006, we have purchased $541 million of short-term investments and redeemed $511 million. Cash flows from investing activities in 2006 also includes $45 million of insurance proceeds related to the settlement of property damage related claims arising from Hurricanes Katrina and Rita.

Table of Contents

Capital Expenditures. Our capital spending for the first nine months of 2006 was $1,325 million, an increase of 67% from our $793 million in capital spending during the same period of 2005. This excludes $23 million of asset retirement costs and hurricane proceeds of $45 million. Of the $1,325 million, we invested $764 million in domestic development, $294 million in domestic exploration, $66 million in other domestic leasehold activity and $201 million internationally.

Our current budget for capital spending in 2006 is $1.9 billion. The total includes $1.8 billion for capital projects and $108 million for capitalized interest and overhead. Approximately 25% of the amount for capital projects is allocated to the Gulf of Mexico (including the traditional shelf, the deep and ultra-deep shelf and deepwater), 19% to the onshore Gulf Coast, 29% to the Mid-Continent, 8% to the Rocky Mountains and 19% to international projects. Actual levels of capital expenditures may vary significantly due to many factors, including the extent to which proved properties are acquired, drilling results, oil and gas prices, industry conditions and the prices and availability of goods and services. We continue to pursue attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. Historically, 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 flow provided by financing activities for the first nine months of 2006 was $309 million compared to $92 million of net cash flow used in financing activities for the same period of 2005. In April 2006, we issued $550 million aggregate principal amount of our 6 5/8% Senior Subordinated Notes due 2016.

In May 2006, we used the proceeds from the offering to redeem $250 million principal amount of our 8 3/8% Senior Subordinated Notes due 2012. In addition, during the nine months ended September 30, 2006, we borrowed and repaid $491 million under our credit arrangements and received proceeds of $9 million from the issuance of shares of our common stock.

During the first nine months of 2005, we repaid a net $120 million under our credit arrangements and received proceeds of $28 million from the issuance of shares of our common stock.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of September 30, 2006.

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In millions)		
Debt:					
7.45% Senior Notes due 2007	$ 125	$ —	$ 125	$ —	$ —
7 5/8% Senior Notes due 2011	175	—	—	175	—
6 5/8% Senior Subordinated Notes due 2014	325	—	—	—	325
6 5/8% Senior Subordinated Notes due 2016	550	—	—	—	550
Total debt	1,175	—	125	175	875
Other obligations:					
Interest payments	586	81	214	121	170
Net derivative (assets) liabilities	4	(172)	161	15	—

Asset retirement obligations	272	49	68	44	111
Operating leases	141	57	65	7	12
Deferred acquisition payments	9	4	5	—	—
Oil and gas activities (1)	364	—	—	—	—
Total other obligations	1,376	19	513	187	293
Total contractual obligations	$ 2,551	$ 19	$ 638	$ 362	$ 1,168

(1) As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work related commitments for, among other things, drilling wells, obtaining and processing seismic data and fulfilling other cash commitments. At September 30, 2006, these work related commitments total $364 million and are comprised of $256 million in the United States and $108 million internationally. These amounts are not included by maturity because their timing cannot be accurately predicted.

Table of Contents

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.

While the use of these hedging arrangements limits the downside risk of adverse price movements, they also may limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX. Historically all of our hedged natural gas and crude oil production has been sold at market prices that have had a high positive correlation to the settlement price for such hedges. Therefore, we believe that our production in these locations is not subject to material basis risk. Nonetheless, due to the currently high levels of natural gas in storage and the significant variances in the basis differential for our production in some areas that are farther removed from the Henry Hub, we have hedged a portion of this basis risk for the period October through December 2006. The price that we receive for natural gas production from the Gulf of Mexico and onshore Gulf Coast, after basis differentials, transportation and handling charges, typically averages $0.40 – $0.60 less per MMBtu than the Henry Hub Index. Realized gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average $0.70 – $0.80 less per MMBtu than the Henry Hub Index. The price we receive for our Gulf Coast oil production typically averages about $2 per barrel below the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains is now averaging about $11 – $13 per barrel below the WTI price. Oil production from the Mid-Continent typically sells at a $1.00 – $1.50 per barrel discount to WTI. Oil production from our operations in Malaysia typically sells at Tapis, or about even with WTI. Oil production from our operations in China is expected to sell for a $15 – $18 per barrel discount to WTI.

As of October 27, 2006, we have entered into derivative contracts as set forth in the tables below. Certain of these contracts do not qualify for or have not been designated as a cash flow hedge for hedge accounting. Please see Note 7, "Commodity Derivative Instruments and Hedging Activities," to our consolidated financial statements appearing earlier in this report for the accounting applicable to both our cash flow hedges as well as our other derivative contracts.

Natural Gas

		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**
October 2006 - December 2006						
Price swap contracts	14,210	$9.14	—	—	—	—
Collar contracts	16,490	—	$9.00 - $9.50	$9.16	$11.00 - $15.40	$12.74

Floor contracts	1,600	—	7.35	7.35	—	—
January 2007 - December 2007						
Price swap contracts	65,730	9.04	—	—	—	—
Collar contracts	72,300	—	6.50 - 10.00	7.90	8.23 - 15.75	10.72
January 2008 - March 2008						
Collar contracts	5,460	—	8.00	8.00	11.05 - 12.40	11.59

Oil

			NYMEX Contract Price Per Bbl					
					Collars			
		Swaps	Additional Put		Floors		Ceilings	
Period and Type of Contract	Volume in MBbls	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average
October 2006 - December 2006								
Price swap contracts	783	$47.71	—	—	—	—	—	—
Collar contracts	211	—	—	—	$50.00 - $60.00	$54.65	$73.90 - $83.75	$79.38
3-Way collar contracts	480	—	$30.00 - $50.00	$37.43	35.00 - 60.00	44.69	50.50 - 80.00	62.21
January 2007 - December 2007								
Price swap contracts	725	51.36	—	—	—	—	—	—
Collar contracts	605	—	—	—	50.00 - 60.00	55.48	77.10 - 83.25	80.40
3-Way collar contracts	3,525	—	25.00 - 50.00	30.02	32.00 - 60.00	37.12	44.70 - 82.00	55.32
January 2008 - December 2008								
3-Way collar contracts	3,294	—	25.00 - 29.00	26.56	32.00 - 35.00	33.00	49.50 - 52.90	50.29
January 2009 - December 2009								
3-Way collar contracts	3,285	—	25.00 - 30.00	27.00	32.00 - 36.00	33.33	50.00 - 54.55	50.62

January 2010 - December 2010								
3-Way collar contracts	3,645	—	25.00 - 32.00	28.60	32.00 - 38.00	34.90	50.00 - 53.50	51.52

Table of Contents

New Accounting Developments

In July 2006, the FASB issued FASB Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes - an interpretation of FAS 109*" (Interpretation No. 48). Interpretation No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken in a tax return. It also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. Interpretation No. 48 is effective for fiscal years beginning after December 15, 2006. Earlier application is encouraged if the company has not yet issued financial statements, including interim financial statements, in the period Interpretation No. 48 is adopted. We are reviewing the interpretation and analyzing the potential impact, if any, of this new guidance.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)." SFAS No. 158 requires recognition of the funded status of a benefit plan on the balance sheet and the recognition through other comprehensive income of gains, losses, prior service costs and credits, net of tax, arising during the period but not included as a component of periodic benefit cost. In addition, the measurement date of plan assets and obligations must be as of the balance sheet date. Additional disclosures in the notes to the financial statements will also be required and guidance is prescribed regarding the selection of discount rates to be used in measuring the benefit obligation. The effective date of SFAS No. 158 is as of the end of the fiscal year ending after December 15, 2006. We do not believe that our financial position, results of operations or cash flows will be significantly impacted by SFAS No. 158.

General Information

General information about us can be found at *www.newfield.com*. In conjunction with our web page, we also maintain an electronic publication entitled @NFX. @NFX is periodically published to provide updates on our operating activities and our latest publicly announced estimates of expected production volumes, costs and expenses for the then current quarter. Recent editions of @NFX are available on our web page. To receive @NFX directly by email, please forward your email address to info@newfield.com or visit our web page and sign up. Unless specifically incorporated, the information about us at www.newfield.com or in any edition of @NFX is not part of this report.

Our annual report 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 to the Securities and Exchange Commission.

Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results such as planned capital expenditures, anticipated hurricane related expenses and the availability of capital resources to fund capital expenditures. 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 refining capacity for the crude oil we produce from our Monument Butte field in Utah;
- the availability of capital resources; and
- the timing of repairs to Gulf of Mexico infrastructure damaged by the 2005 hurricanes.

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.

Table of Contents

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 of natural 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.

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.

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

MMBtu. One million Btus.

MMMBtu. One billion Btus.

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.

NYMEX. The New York Mercantile Exchange.

Table of Contents

Item 3. 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 flows 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 also may 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 2 of this report and the discussion and tables in Note 7, "Commodity Derivative Instruments and Hedging Activities," to our consolidated financial statements appearing earlier in this report.

Interest Rates

At September 30, 2006, 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
7 5/8% Senior Notes due 2011(1)	125	50
6 5/8% Senior Subordinated Notes due 2014	325	
6 5/8% Senior Subordinated Notes due 2016	550	
Total long-term debt	$ 1,075	$ 100

(1) $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 7 5/8% Senior Notes due 2011 are subject to interest rate swaps. These swaps provide for us to pay variable and receive fixed interest payments, and are designated as fair value hedges of a portion of our outstanding senior notes.

We consider our interest rate exposure to be minimal because as of September 30, 2006 about 91% of our long-term debt obligations, after taking into account our interest rate swap agreements, were at fixed rates.

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 September 30, 2006.

Table of Contents

Item 4. 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 September 30, 2006 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.

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, to determine whether any changes occurred during the third quarter of 2006 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.

Table of Contents

PART II

Item 1. Legal Proceedings

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

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table sets forth certain information with respect to repurchases of our common stock during the nine months ended September 30, 2006:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under The Plans or Programs
January 1 - January 31, 2006	—	—	—	—
February 1 - February 28, 2006	60,716	$51.27	—	—
March 1 - March 31, 2006	—	—	—	—
April 1 - April 30, 2006	199	41.71	—	—
May 1 - May 31, 2006	106	47.05	—	—
June 1 - June 30, 2006	265	43.06	—	—
July 1 - July 31, 2006	106	48.66	—	—
August 1 - August 31, 2006	1,230	43.98	—	—
September 1 - September 30, 2006	865	38.65	—	—

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted shares. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have such a publicly announced program.

Item 6. Exhibits

(a) Exhibits:

Exhibit Number	Description
31.1	

	Certification of Chief Executive Officer of Newfield 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 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 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 pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Table of Contents

SIGNATURE

Pursuant to the requirements 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.

NEWFIELD EXPLORATION COMPANY

Date: October 31, 2006	By:	/s/ TERRY W. RATHERT Terry W. Rathert Senior Vice President and Chief Financial Officer

Table of Contents

EXHIBIT INDEX

Exhibit Number	Description
31.1	Certification of Chief Executive Officer of Newfield 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 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 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 pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002