CHESAPEAKE ENERGY CORP
Form 10-Q
August 08, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended June 30, 2007

¨ **Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from to

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1395733**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
6100 North Western Avenue	
Oklahoma City, Oklahoma	**73118**
(Address of principal executive offices)	**(Zip Code)**

(405) 848-8000

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 x 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.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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

As of August 6, 2007, there were 473,520,004 shares of our $0.01 par value common stock outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2007	December 31, 2006
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4	$ 3
Accounts receivable	905	845
Deferred income taxes	11	
Short-term derivative instruments	278	225
Inventory and other	95	81
Total Current Assets	1,293	1,154
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full-cost accounting:		
Evaluated oil and natural gas properties	25,451	21,949
Unevaluated properties	4,257	3,797
Less: accumulated depreciation, depletion and amortization of oil and natural gas properties	(6,120)	(5,292)
Total oil and natural gas properties, at cost based on full-cost accounting	23,588	20,454
Other property and equipment:		
Natural gas gathering systems	742	552
Drilling rigs	306	301
Natural gas compressors	183	127
Buildings and land	518	429
Other	294	241
Less: accumulated depreciation and amortization of other property and equipment	(268)	(200)
Total Other Property and Equipment	1,775	1,450
Total Property and Equipment	25,363	21,904
OTHER ASSETS:		
Investments	643	699
Long-term derivative instruments	44	339
Other assets	353	321
Total Other Assets	1,040	1,359
TOTAL ASSETS	$ 27,696	$ 24,417

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	June 30, 2007	December 31, 2006
	($ in millions)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 918	$ 860
Accrued liabilities	530	419
Short-term derivative instruments	190	112
Revenues and royalties due others	400	318
Accrued interest	175	142
Deferred income taxes		39
Total Current Liabilities	2,213	1,890
LONG-TERM LIABILITIES:		
Long-term debt, net	9,417	7,376
Deferred income tax liability	3,701	3,317
Asset retirement obligation	208	193
Long-term derivative instruments	257	160
Revenues and royalties due others	38	30
Other liabilities	236	200
Total Long-Term Liabilities	13,857	11,276
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
4.125% cumulative convertible preferred stock, 3,062 and 3,065 shares issued and outstanding as of June 30, 2007 and December 31, 2006, respectively, entitled in liquidation to $3 million	3	3
5.00% cumulative convertible preferred stock (series 2005), 4,600,000 shares issued and outstanding as of June 30, 2007 and December 31, 2006, entitled in liquidation to $460 million	460	460
4.50% cumulative convertible preferred stock, 3,450,000 shares issued and outstanding as of June 30, 2007 and December 31, 2006, entitled in liquidation to $345 million	345	345
5.00% cumulative convertible preferred stock (series 2005B), 5,750,000 shares issued and outstanding as of June 30, 2007 and December 31, 2006, entitled in liquidation to $575 million	575	575
6.25% mandatory convertible preferred stock, 2,300,000 shares issued and outstanding as of June 30, 2007 and December 31, 2006, respectively, entitled in liquidation to $575 million	575	575
Common Stock, $.01 par value, 750,000,000 shares authorized, 471,791,692 and 458,600,789 shares issued at June 30, 2007 and December 31, 2006, respectively	5	5
Paid-in capital	5,929	5,873
Retained earnings	3,576	2,913
Accumulated other comprehensive income, net of tax of ($103) million and ($319) million, respectively	170	528
Less: treasury stock, at cost; 704,258 and 1,167,007 common shares as of June 30, 2007 and December 31, 2006, respectively	(12)	(26)
Total Stockholders Equity	11,626	11,251

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 27,696	$ 24,417

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	($ in millions except per share data)			
REVENUES:				
Oil and natural gas sales	$ 1,548	$ 1,186	$ 2,672	$ 2,697
Oil and natural gas marketing sales	523	368	945	772
Service operations revenue	34	30	67	60
Total Revenues	2,105	1,584	3,684	3,529
OPERATING COSTS:				
Production expenses	153	120	295	240
Production taxes	53	34	95	89
General and administrative expenses	54	34	107	63
Oil and natural gas marketing expenses	504	356	911	747
Service operations expense	23	16	44	30
Oil and natural gas depreciation, depletion and amortization	442	328	835	633
Depreciation and amortization of other assets	40	23	76	47
Employee retirement expense				55
Total Operating Costs	1,269	911	2,363	1,904
INCOME FROM OPERATIONS	836	673	1,321	1,625
OTHER INCOME (EXPENSE):				
Interest and other income	1	5	10	15
Interest expense	(84)	(73)	(162)	(146)
Gain on sale of investments	83		83	117
Total Other Income (Expense)		(68)	(69)	(14)
INCOME BEFORE INCOME TAXES	836	605	1,252	1,611
INCOME TAX EXPENSE:				
Current	11		11	
Deferred	307	245	465	627
Total Income Tax Expense	318	245	476	627
NET INCOME	518	360	776	984
PREFERRED STOCK DIVIDENDS	(26)	(18)	(52)	(37)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK		(10)		(11)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 492	$ 332	$ 724	$ 936
EARNINGS PER COMMON SHARE:				

Basic	$ 1.09	$ 0.87	$ 1.60	$ 2.50
Assuming dilution	$ 1.01	$ 0.82	$ 1.51	$ 2.27
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.0675	$ 0.06	$ 0.1275	$ 0.11
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	452	381	452	375
Assuming dilution	515	428	515	433

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30, 2007	2006
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 776	$ 984
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	903	674
Deferred income taxes	460	627
Unrealized (gains) losses on derivatives	152	(212)
Amortization of loan costs and bond discount	12	9
Realized gains on financing derivatives	(51)	(60)
Stock-based compensation	30	67
Gain on sale of investments	(83)	(117)
Income from equity investments	(4)	(7)
Other	5	(4)
Change in assets and liabilities	(78)	84
Cash provided by operating activities	2,122	2,045
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisitions of oil and natural gas companies, proved and unproved properties, net of cash acquired	(1,123)	(1,704)
Exploration and development of oil and natural gas properties	(2,598)	(1,689)
Additions to other fixed assets	(414)	(181)
Additions to drilling rig equipment	(70)	(244)
Additions to investments	(12)	(38)
Acquisition of trucking company, net of cash acquired		(45)
Proceeds from sale of investments	124	159
Proceeds from sale of drilling rigs and equipment	87	
Deposits for acquisitions	(5)	(43)
Sale of non-oil and natural gas assets	8	1
Cash used in investing activities	(4,003)	(3,784)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	3,544	4,055
Payments on long-term borrowings	(2,624)	(4,127)
Proceeds from issuance of senior notes, net of offering costs	1,124	969
Proceeds from issuance of common stock, net of offering costs		699
Proceeds from issuance of preferred stock, net of offering costs		485
Cash paid for common stock dividends	(54)	(37)
Cash paid for preferred stock dividends	(52)	(38)
Purchase of treasury shares		(86)
Derivative settlements	(52)	(51)
Net increase (decrease) in outstanding payments in excess of cash balance	(10)	42
Cash received from exercise of stock options	6	68

Excess tax benefit from stock-based compensation	8	81
Other financing costs	(8)	(15)
Cash provided by financing activities	1,882	2,045
Net increase in cash and cash equivalents	1	306
Cash and cash equivalents, beginning of period	3	60
Cash and cash equivalents, end of period	$ 4	$ 366

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 123	$ 148
Income taxes, net of refunds received	$ 15	$

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of June 30, 2007 and 2006, dividends payable on our common and preferred stock were $56 million and $42 million, respectively.

For the six months ended June 30, 2007 and 2006, oil and natural gas properties were adjusted by $101 million and $81 million, respectively, for net income tax liabilities related to acquisitions.

For the six months ended June 30, 2007 and 2006, accrued exploration and development costs of $55 million and $42 million, respectively, were recorded as additions to oil and natural gas properties.

We recorded non-cash asset additions to oil and natural gas properties of $8 million and $9 million for the six months ended June 30, 2007 and 2006, respectively, for asset retirement obligations.

For the six months ended June 30, 2007, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock, and for the six months ended June 30, 2006, holders of our 4.125% preferred stock exchanged 2,750 shares for 172,594 shares of common stock in privately negotiated exchanges.

For the six months ended June 30, 2006, holders of our 5.0% (Series 2003) cumulative convertible preferred stock exchanged 183,273 shares for 1,140,223 shares of common stock in privately negotiated exchanges.

For the six months ended June 30, 2006, holders of our 6.0% cumulative convertible preferred stock converted 99,310 shares into 482,694 shares of common stock.

For the six months ended June 30, 2006, holders of our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock exchanged 83,245 shares and 804,048 shares for 5,248,126 and 4,972,786 shares of common stock, respectively, in public exchange offers.

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(Unaudited)

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 1,958	$ 1,577
Issuance of 6.25% mandatory convertible preferred stock		500
Exchange of common stock for 3 and 85,995 shares of 4.125% preferred stock		(86)
Exchange of common stock for 0 and 987,321 shares of 5.00% preferred stock (Series 2003)		(99)
Exchange of common stock for 0 and 99,310 shares of 6.00% preferred stock		(5)
Balance, end of period	1,958	1,887
COMMON STOCK:		
Balance, beginning of period	5	4
Exchange of 180 and 12,016,423 shares of common stock for preferred stock		
Issuance of 0 and 25,000,000 shares of common stock		
Balance, end of period	5	4
PAID-IN CAPITAL:		
Balance, beginning of period	5,873	3,803
Issuance of 0 and 25,000,000 shares of common stock		726
Exchange of 180 and 12,016,423 shares of common stock for preferred stock		189
Stock-based compensation	42	72
Adoption of SFAS 123(R)		(89)
Offering expenses		(43)
Exercise of stock options	6	68
Tax benefit from exercise of stock options and restricted stock	8	81
Release of 0 and 6,400,000 shares of treasury stock upon exercise of stock options		(72)
Balance, end of period	5,929	4,735
RETAINED EARNINGS:		
Balance, beginning of period	2,913	1,101
Net income	776	984
Dividends on common stock	(58)	(44)
Dividends on preferred stock	(51)	(35)
Adoption of FIN 48	(4)	
Balance, end of period	3,576	2,006
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	528	(195)
Hedging activity	(356)	675
Marketable securities activity	(2)	(83)

Balance, end of period	170	397
UNEARNED COMPENSATION:		
Balance, beginning of period		(89)
Adoption of SFAS 123(R)		89
Balance, end of period		
TREASURY STOCK - COMMON:		
Balance, beginning of period	(26)	(26)
Release of 463,085 and 44,477 shares for company benefit plans	14	1
Purchase of 0 and 2,707,471 shares of treasury stock		(86)
Release of 0 and 6,400,000 shares upon exercise of stock options		72
Balance, end of period	(12)	(39)
TOTAL STOCKHOLDERS EQUITY	$ 11,626	$ 8,990

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	($ in millions)			
Net income	$ 518	$ 360	$ 776	$ 984
Other comprehensive income, net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $67 million, $229 million, ($65) million and $632 million	109	382	(104)	1,049
Reclassification of gain on settled contracts, net of income taxes of ($40) million, ($86) million, ($178) million and ($164) million	(64)	(142)	(292)	(271)
Unrealized gain (loss) on ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $4 million, ($25) million, $24 million and ($62) million	6	(42)	40	(103)
Unrealized loss on marketable securities, net of income taxes of ($2) million, ($19) million, ($1) million and ($6) million	(4)	(31)	(2)	(10)
Reclassification of gain on sales of investments, net of income taxes of $0, $0, $0 and ($46) million				(73)
Comprehensive income	$ 565	$ 527	$ 418	$ 1,576

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation and its subsidiaries have been prepared in accordance with the instructions to Form 10-Q as prescribed by the Securities and Exchange Commission. Chesapeake s 2006 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair statement of the results for the interim periods have been reflected. The results for the three and six months ended June 30, 2007 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and six months ended June 30, 2007 (the Current Quarter and the Current Period , respectively) and the three and six months ended June 30, 2006 (the Prior Quarter and the Prior Period , respectively).

Stock-Based Compensation

Chesapeake s stock-based compensation programs primarily consist of restricted stock and stock options issued to employees and non-employee directors. To the extent compensation cost relates to employees directly involved in oil and natural gas exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expenses, production expenses, oil and natural gas marketing expenses, service operations expense or employee retirement expense. We recorded the following stock-based compensation during the three and six months ended June 30, 2007 and 2006, respectively ($ in millions):

For the three months ended June 30:	**2007**	**2006**
Production expenses	$ 3	$ 1
General and administrative expenses	12	7
Oil and natural gas marketing expenses	1	
Oil and natural gas properties	12	5
Total	$ 28	$ 13

For the six months ended June 30:	**2007**	**2006**
Production expenses	$ 6	$ 3
General and administrative expenses	22	13
Oil and natural gas marketing expenses	1	
Service operations expense	1	
Employee retirement expense		51
Oil and natural gas properties	22	9
Total	$ 52	$ 76

Restricted Stock. Chesapeake regularly issues shares of restricted common stock to employees and to non-employee directors. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is generally four or five years from the date of grant for employees and three years for non-employee directors.

A summary of the status of the unvested shares of restricted stock as of June 30, 2007, and changes during the Current Period, is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2007	7,074,761	$ 25.85
Granted	12,510,843	$ 34.03
Vested	(970,018)	$ 22.45
Forfeited	(148,402)	$ 33.53
Unvested shares as of June 30, 2007	18,467,184	$ 31.52

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $28 million.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Included in the 12.5 million shares of restricted stock granted during the Current Period are 9.8 million shares of restricted stock granted during the Current Quarter to our employees (except our CEO and CFO, who did not participate in the stock awards) under a long-term stock incentive and retention program. These shares vest 50% in August 2009 with the remaining 50% vesting in August 2011.

As of June 30, 2007, there was $553 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 3.46 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the Current Period and the Prior Period, we recognized excess tax benefits related to restricted stock of $1 million and $3 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits. In the Current Quarter and the Prior Quarter, the amount of excess tax benefits was nominal.

Stock Options. Prior to 2005, we granted stock options under several stock compensation plans. Outstanding options expire ten years from the date of grant and are exercisable over a four-year period.

The following table provides information related to stock option activity during the Current Period:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[a] ($ in millions)
Outstanding at January 1, 2007	6,605,703	$ 7.43	5.36	$ 143
Exercised	(993,208)	$ 6.43		$ 26
Forfeited	(12,108)	$ 9.73		
Outstanding at June 30, 2007	5,600,387	$ 7.60	4.89	$ 151
Exercisable at June 30, 2007	5,527,914	$ 7.54	4.87	$ 150

(a) The intrinsic value of a stock option is the amount by which the current market value or the market value upon exercise of the underlying stock exceeds the exercise price of the option.

As of June 30, 2007, there was a nominal amount of total unrecognized compensation cost related to unvested stock options. The cost is expected to be recognized over a weighted average period of approximately 180 days.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of $4 million, $4 million, $7 million and $79 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Income Taxes

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006.

Chesapeake adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, Chesapeake recognized a $7 million liability for accrued interest associated with uncertain tax positions which was accounted for as a reduction to the January 1, 2007 balance of retained earnings, net of tax. At the date of adoption, we had approximately $142 million of unrecognized tax benefits related to alternative minimum tax (AMT) associated with uncertain tax positions. As of June 30, 2007, the amount of unrecognized tax benefits related to AMT associated with uncertain tax positions was $154 million. These AMT liabilities can be utilized as credits against future regular tax liabilities. The uncertain tax positions identified would not have a material effect on the effective tax rate. At June 30, 2007, we had a liability of $10 million for interest related to these same uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Chesapeake files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. With few exceptions, Chesapeake is no longer subject to the U.S. federal, state and local income tax examinations by tax authorities for years prior to 2003. The Internal Revenue Service (IRS) commenced an examination of Chesapeake s U.S. income tax returns for 2003 and 2004 in 2006 that is anticipated to be completed by the end of 2007. As of June 30, 2007, the IRS has proposed a limited number of adjustments. We are currently evaluating the proposed adjustments, but we do not anticipate that the adjustments would result in a material change to our financial position, results of operations or cash flows.

Critical Accounting Policies

We consider accounting policies related to hedging, oil and natural gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2006.

2. Financial Instruments and Hedging Activities

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of June 30, 2007, our oil and natural gas derivative instruments were comprised of swaps, cap-swaps, knockout swaps, basis protection swaps, call options, collars and three-way collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty.

For knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

For call options, Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

A three-way collar contract consists of a standard collar contract plus a written put option with a strike price below the floor price of the collar. In addition to the settlement of the collar, the put option requires us to make a payment to the counterparty equal to the difference between the put option price and the settlement price if the settlement price for any settlement period is below the put option strike price.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. Generally, at the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural gas sales in the month of related production.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap. Changes in the value of cap-swaps and counter-swaps are recorded as adjustments to oil and natural gas sales.

In accordance with FASB Interpretation No. 39, to the extent that a legal right of set-off exists, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets.

Gains or losses from certain derivative transactions are reflected as adjustments to oil and natural gas sales on the condensed consolidated statements of operations. Realized gains (losses) are included in oil and natural gas sales in the month of related production. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within oil and natural gas sales. Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales as unrealized gains (losses). The components of oil and natural gas sales for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	($ in millions)			
Oil and natural gas sales	$ 1,199	$ 912	$ 2,200	$ 1,977
Realized gains on oil and natural gas derivatives	197	258	630	506
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	162	(49)	(94)	49
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(10)	65	(64)	165
Total oil and natural gas sales	$ 1,548	$ 1,186	$ 2,672	$ 2,697

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The estimated fair values of our oil and natural gas derivative instruments as of June 30, 2007 and December 31, 2006 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	June 30, 2007	December 31, 2006
	($ in millions)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ (95)	$ 1
Natural gas basis protection swaps	174	187
Fixed-price natural gas knockout swaps	91	122
Fixed-price natural gas counter-swaps		(5)
Natural gas call options[(a)]	(141)	(5)
Fixed-price natural gas collars	(13)	(7)
Fixed-price natural gas three-way collars	(9)	
Fixed-price oil swaps	(14)	28
Fixed-price oil cap-swaps	9	24
Fixed-price oil knockout swaps	(8)	
Oil call options[(b)]	(17)	
Estimated fair value	$ (23)	$ 345

(a) After adjusting for $138 million and $15 million of unrealized premiums, the cumulative unrealized gain (loss) related to these call options as of June 30, 2007 and December 31, 2006 was ($3) million and $10 million, respectively.

(b) After adjusting for $13 million of unrealized premiums, the cumulative unrealized loss related to these call options as of June 30, 2007 was ($4) million.

In 2006 and 2007, Chesapeake lifted a portion of its 2007, 2008 and 2009 hedges and as a result has approximately $350 million of deferred hedging gains as of June 30, 2007. These gains have been recorded in accumulated other comprehensive income or as an unrealized gain in oil and natural gas sales. For amounts originally recorded in other comprehensive income, the gain will be recognized in oil and natural gas sales in the month of the hedged production.

Based upon the market prices at June 30, 2007, we expect to transfer approximately $178 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of June 30, 2007 are expected to mature by December 31, 2012.

We have three secured hedging facilities maturing in 2011, each of which permits us to enter into cash-settled oil and natural gas commodity transactions, valued by the counterparty, for up to a maximum value. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. The hedging facilities are subject to a 1% per annum exposure fee, which is assessed quarterly based on the average of the daily negative fair value amounts of the hedges, if any, during the quarter. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate oil and natural gas production volumes that we are permitted to hedge under all of our agreements at any one time. The maximum permitted value of transactions under each facility and the fair values of outstanding transactions are shown below.

	Secured Hedging Facilities #1	#2 ($ in millions)	#3
Maximum permitted value of transactions under facility	$ 750	$ 500	$ 500
Fair value of outstanding transactions, as of June 30, 2007	$ 11	$ (97)	$ (23)

We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to

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the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element, and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs. The aggregate fair value of the remaining CNR derivatives as of June 30, 2007 was a liability of $253 million.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the condensed consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from certain derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. Realized gains (losses) included in interest expense were less than ($1) million, $1 million, ($2) million and $2 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were $7 million, ($1) million, $6 million and ($2) million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

As of June 30, 2007, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value ($ in millions)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (4)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	(9)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	(9)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(12)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	(7)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	(13)
December 2006 July 2013	$ 250,000,000	7.625%	6 month LIBOR plus 266.5 basis points	(8)
January 2007 July 2013	$ 250,000,000	7.625%	6 month LIBOR plus 251 basis points	(6)
February 2007 August 2017	$ 250,000,000	6.500%	6 month LIBOR plus 124.5 basis points	(8)
June 2007 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 40.3 basis points	(4)
June 2007 June 2015	$ 250,000,000	6.375%	6 month LIBOR plus 68.25 basis points	(3)
June 2007 November 2020	$ 250,000,000	6.875%	6 month LIBOR plus 132 basis points	(4)
				$ (87)

In the Current Period, we sold call options on three of our interest rate swaps and received $5 million in premiums. One of the options expired unexercised in the Current Quarter.

In the Current Period, we closed two interest rate swaps for a gain totaling $4 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes.

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Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties will pay Chesapeake 19 million and Chesapeake will pay the counterparties $30 million, which will yield an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($811 million at June 30, 2007) using an exchange rate of $1.3520 to 1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as a liability of $13 million at June 30, 2007. The translation adjustment to notes payable is completely offset by the fair value of the cross currency swap and therefore there is no impact to the consolidated statement of operations. The remaining value of the cross currency swap related to future interest payments is reported in other comprehensive income.

Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards No. 107, *Disclosures About Fair Value of Financial Instruments*. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of financial instruments comprising current assets and current liabilities approximate the fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term fixed-rate debt and our convertible preferred stock using primarily quoted market prices. Our carrying amounts for such debt, excluding discounts or premiums related to interest rate derivatives, at June 30, 2007 and December 31, 2006 were $8.388 billion and $7.215 billion, respectively, compared to approximate fair values of $8.417 billion and $7.336 billion, respectively. The carrying amount for our convertible preferred stock as of June 30, 2007 and December 31, 2006 was $1.958 billion, compared to approximate fair values of $2.045 billion and $1.949 billion, respectively.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in equity instruments and accounts receivable. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

3. Contingencies and Commitments

Litigation

We are involved in various disputes incidental to our business operations, including claims from royalty owners regarding volume measurements, post-production costs and prices for royalty calculations. In *Tawney, et al. v. Columbia Natural Resources, Inc.*, Chesapeake s wholly owned subsidiary Chesapeake Appalachia, L.L.C., formerly known as Columbia Natural Resources, LLC (CNR), is a defendant in a class action lawsuit in the Circuit Court of Roane County, West Virginia filed in 2003 by royalty owners. The plaintiffs allege that CNR underpaid royalties by improperly deducting post-production costs, failing to pay royalty on total volumes of natural gas produced and not paying a fair value for the natural gas produced from their leases. The plaintiff class consists of West Virginia royalty owners receiving royalties after July 31, 1990 from CNR. Chesapeake acquired CNR in November 2005, and its seller acquired CNR in 2003 from NiSource Inc. NiSource, a co-defendant in the case, has managed the litigation and indemnified Chesapeake against underpayment claims based on the use of fixed prices for natural gas production sold under certain forward sale contracts and other claims with respect to CNR s operations prior to September 2003.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of $404 million, consisting of $134 million in compensatory damages and $270 million in punitive damages. Most of the damages awarded by the jury relate to issues not yet addressed by the West Virginia Supreme Court of Appeals, although in June 2006 that Court ruled against the defendants on two certified questions regarding the deductibility of post-production expenses. The jury found fraudulent conduct by the defendants with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions. On June 28, 2007, the Circuit Court sustained the jury verdict for punitive damages.

After judgment has been entered, Chesapeake and NiSource intend to file additional post-trial motions seeking to set aside the judgment. Chesapeake and NiSource maintain CNR acted in good faith and paid royalties in accordance with lease terms and West Virginia law, and will appeal unless the judgment is substantially reduced as a result of post-trial motions. Chesapeake has established an accrual for amounts it believes will not be indemnified. Should a final nonappealable judgment be entered, Chesapeake believes its share of damages will not have a material adverse effect on its results of operations, financial condition or liquidity.

Chesapeake is subject to other legal proceedings and claims which arise in the ordinary course of business. In our opinion, the final resolution of these proceedings and claims will not have a material effect on the company.

Employment Agreements with Officers

Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and other executive officers, which provide for annual base salaries, various benefits and eligibility for bonus compensation. The agreement with the chief executive officer has a term of five years commencing January 1, 2007. The term of the agreement is automatically extended for one additional year on each December 31 unless the company provides 30 days notice of non-extension. In the event of termination of employment without cause, the chief executive officer s base compensation (defined as base salary plus bonus compensation received during the preceding 12 months) and benefits would continue during the remaining term of the agreement. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation and three times the value of the prior year s benefits, plus a tax gross-up payment, upon the happening of certain events following a change of control, and the company will also provide him office space and administrative and accounting support for a period of 12 months thereafter. Any stock-based awards held by the chief executive officer and deferred compensation will immediately become 100% vested upon termination of employment without cause, a change of control event, incapacity, death or retirement at or after age 55, and any unexercised stock options will not terminate as the result of termination of employment.

The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2009. These agreements provide for the continuation of salary for one year in the event of termination of employment without cause and, in the event of a change of control, a payment in the amount of two times the executive officer s annual base compensation. Any stock-based awards held by such executive officers will immediately become 100% vested upon termination of employment without cause, a change of control, death or retirement at or after age 55.

Environmental Risk

Due to the nature of the oil and natural gas business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a contingent liability, its amount and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at June 30, 2007.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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Rig Leases

In a series of transactions in 2006 and 2007, our wholly-owned subsidiary, Nomac Drilling Corporation, has sold 33 of its drilling rigs and related equipment for $331 million and entered into a master lease agreement under which it agreed to lease the rigs from the buyer for initial terms of eight to ten years for rental payments of approximately $44 million annually. Nomac s lease obligations are guaranteed by Chesapeake and its other material domestic subsidiaries. These transactions were recorded as sales and operating leasebacks, with an aggregate deferred gain of $32 million on the sales which will be amortized to service operations expense over the lease term. Under the rig leases, we have the option to purchase the rigs in 2013 or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal. Commitments related to these lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2007, the minimum aggregate future rig lease payments were approximately $344 million.

Transportation Contracts

Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from one to 93 years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter s Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company receives rights to flow natural gas production through pipelines located in highly competitive markets. As of June 30, 2007, the aggregate amount of such required demand payments was approximately $374 million (excluding demand charges for pipeline projects that are currently seeking regulatory approval).

Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to use approximately 38 rigs with terms of one to three years. As of June 30, 2007, the aggregate drilling rig commitment was approximately $301 million.

As of June 30, 2007, Chesapeake s service operations subsidiaries have contracted to acquire six rigs to be constructed during 2007. The total remaining cost of the rigs is estimated to be approximately $45 million.

Other Commitments

As of June 30, 2007, Chesapeake has contracted to acquire compressors during 2007, 2008 and 2009 for a total commitment of $178 million which is not recorded in the accompanying condensed consolidated balance sheets.

Chesapeake and a leading investment bank have an agreement to lend Mountain Drilling Company, of which Chesapeake is a 49% equity owner, up to $32 million each through December 31, 2009. At June 30, 2007, Mountain Drilling owes Chesapeake $30 million under this agreement.

Chesapeake has an agreement to lend Ventura Refining and Transmission LLC, of which Chesapeake is a 25% equity owner, up to $26 million through February 28, 2008. At June 30, 2007, there was $21 million outstanding under this agreement. Additionally, we have agreed to guarantee various commitments for Ventura, up to $75 million, to support their operating activities.

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4. Net Income Per Share

Statement of Financial Accounting Standards No. 128, *Earnings Per Share*, requires presentation of basic and diluted earnings per share, as defined, on the face of the statements of operations for all entities with complex capital structures. SFAS 128 requires a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

The following securities were not included in the calculation of diluted earnings per share, as the effect was antidilutive:

For the Prior Quarter, diluted shares do not include the common stock equivalent of our 4.125% preferred stock outstanding prior to conversion (convertible into 3,406,130 shares) and the preferred stock adjustment to net income does not include $8 million of dividends and loss on conversion related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

For the Prior Quarter, diluted shares do not include the common stock equivalent of our 5.0% (Series 2003) preferred stock outstanding prior to conversion (convertible into 3,339,576 shares), and the preferred stock adjustment to net income does not include $3 million of dividends and loss on conversion related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

Reconciliations for the three and six months ended June 30, 2007 and 2006 are as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
For the Three Months Ended June 30, 2007:			
Basic EPS:			
Income available to common shareholders	$ 492	452	$ 1.09
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		18	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B) `		15	
Common shares assumed issued for 6.25% mandatory convertible preferred stock		16	
Employee stock options		4	
Restricted stock		2	
Preferred stock dividends	26		
Diluted EPS Income available to common shareholders and assumed conversions	$ 518	515	$ 1.01

For the Three Months Ended June 30, 2006:			
Basic EPS:			
Income available to common shareholders	$ 332	381	$ 0.87
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		18	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B) `		15	
Employee stock options		5	
Restricted stock		1	
Preferred stock dividends	17		
Diluted EPS Income available to common shareholders and assumed conversions	$ 349	428	$ 0.82

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

For the Six Months Ended June 30, 2007:			
Basic EPS:			
Income available to common shareholders	$ 724	452	$ 1.60
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		18	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B) `		15	
Common shares assumed issued for 6.25% mandatory convertible preferred stock		16	
Employee stock options		4	
Restricted stock		2	
Preferred stock dividends	52		
Diluted EPS Income available to common shareholders and assumed conversions	$ 776	515	$ 1.51
For the Six Months Ended June 30, 2006:			
Basic EPS:			
Income available to common shareholders	$ 936	375	$ 2.50
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		18	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B) `		15	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion, 4.125% convertible preferred stock		4	
5.00% convertible preferred stock (Series 2003)		4	
Employee stock options		7	
Restricted stock		2	
Loss on redemption of preferred stock	11		
Preferred stock dividends	37		
Diluted EPS Income available to common shareholders and assumed conversions	$ 984	433	$ 2.27

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5. Stockholders Equity

The following is a summary of the changes in our common shares outstanding for the six months ended June 30, 2007 and 2006:

	2007	2006
	(in thousands)	
Shares outstanding at January 1	458,601	375,511
Stock option exercises	985	6,176
Restricted stock issuances	12,206	1,756
Preferred stock conversions/exchanges		12,017
Common stock issuances		25,000
Shares outstanding at June 30	471,792	420,460

The following is a summary of the changes in our preferred shares outstanding for the six months ended June 30, 2007 and 2006:

	6.00%	5.00% (2003)	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
			(in thousands)				
Shares outstanding at January 1, 2007			3	4,600	3,450	5,750	2,300
Conversion/exchange of preferred for common stock							
Shares outstanding at June 30, 2007			3	4,600	3,450	5,750	2,300
Shares outstanding at January 1, 2006	99	1,026	89	4,600	3,450	5,750	
Preferred stock issuances							2,000
Conversion/exchange of preferred for common stock	(99)	(987)	(86)				
Shares outstanding at June 30, 2006		39	3	4,600	3,450	5,750	2,000

In the Current Quarter, we issued 9.8 million shares of restricted stock to our employees (except for our CEO and CFO, who did not participate in the stock awards) under a long-term stock incentive and retention program. These shares vest 50% in August 2009 with the remaining 50% vesting in August 2011.

During the Current Period, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock.

In the Prior Period, shares of our preferred stock were exchanged for or converted into common stock as follows:

183,273 shares of 5.0% (Series 2003) cumulative convertible preferred stock were exchanged for or converted into 1,140,223 shares of common stock in privately negotiated exchange transactions or pursuant to conversion rights;

804,048 shares of such 5.0% (Series 2003) cumulative convertible preferred stock were exchanged for 4,972,786 shares of common stock pursuant to a tender offer;

2,750 shares of 4.125% cumulative convertible preferred stock were exchanged for 172,594 shares of common stock in privately negotiated exchange transactions;

83,245 shares of such 4.125% cumulative convertible preferred stock were exchanged for 5,248,126 shares of common stock pursuant to a tender offer; and

the remaining 99,310 shares of 6.0% cumulative convertible preferred stock were exchanged for or converted into 482,694 shares of common stock in privately negotiated exchange transactions or pursuant to conversion rights.

In connection with the exchanges noted above, we recorded losses of $10 million and $11 million in the Prior Quarter and the Prior Period, respectively. In general, the losses are equal to the excess of the fair value of all common stock exchanged over the fair value of the securities issuable pursuant to the original conversion terms of the preferred stock.

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6. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following as of June 30, 2007 and December 31, 2006:

	June 30, 2007	December 31, 2006
	($ in millions)	
7.5% Senior Notes due 2013	$ 364	$ 364
7.625% Senior Notes due 2013	500	500
7.0% Senior Notes due 2014	300	300
7.5% Senior Notes due 2014	300	300
7.75% Senior Notes due 2015	300	300
6.375% Senior Notes due 2015	600	600
6.625% Senior Notes due 2016	600	600
6.875% Senior Notes due 2016	670	670
6.5% Senior Notes due 2017	1,100	1,100
6.25% Euro-denominated Senior Notes due 2017[a]	811	792
6.25% Senior Notes due 2018	600	600
6.875% Senior Notes due 2020	500	500
2.75% Contingent Convertible Senior Notes due 2035[b]	690	690
2.5% Contingent Convertible Senior Notes due 2037[b]	1,150	
Revolving bank credit facility	1,098	178
Discount on senior notes	(97)	(101)
Discount for interest rate derivatives[c]	(69)	(17)
Total notes payable and long-term debt	$ 9,417	$ 7,376

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3520 to 1.00 and $1.3197 to 1.00 as of June 30, 2007 and December 31, 2006, respectively. See Note 2 for information on our related cross currency swap.

(b) The holders of our Contingent Convertible Senior Notes may require us to repurchase all or a portion of their notes 5, 10, 15 or 20 years prior to the maturity date, or upon a fundamental change, at 100% of the principal amount of the notes, payable in cash. The notes are convertible, at the holder s option, prior to maturity under certain circumstances, into cash and, if applicable, shares of our common stock using a net share settlement process. In general, upon conversion of a convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. In addition, we will pay contingent interest on the convertible senior notes, beginning with the six-month interest period ending May 14, 2016 with respect to the 2.75% Contingent Convertible Senior Notes due 2035 and November 14, 2017 with respect to the 2.5% Contingent Convertible Senior Notes due 2037, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash.

(c) See Note 2 for discussion related to these instruments.

No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

Our outstanding senior notes are unsecured senior obligations of Chesapeake that rank equally in right of payment with all of our existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. We may redeem the senior notes, other than the 2.75% Contingent Convertible Senior Notes due 2035 and the 2.5% Contingent Convertible Senior Notes due 2037, at any time at specified make-whole or redemption prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale-leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes have been fully and unconditionally guaranteed, jointly and severally, by all of our wholly owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis.

We have a $2.5 billion syndicated revolving bank credit facility which matures in February 2011. As of June 30, 2007, we had $1.098 billion in outstanding borrowings under our facility and utilized approximately $4 million of the facility for various letters of credit. Borrowings under our facility are collateralized by certain producing oil and natural gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California,

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

N.A. or the federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently, the commitment fee rate is 0.25% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which govern our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.45 to 1 and our indebtedness to EBITDA ratio was 2.00 to 1 at June 30, 2007. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

Two of our subsidiaries, Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility. The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly owned subsidiaries except minor subsidiaries.

7. Segment Information

In accordance with Statement of Financial Accounting Standards No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have two reportable operating segments. Our exploration and production segment and oil and natural gas marketing segment are managed separately because of the nature of their products and services. The exploration and production segment is responsible for finding and producing oil and natural gas. The marketing segment is responsible for gathering, processing, compressing, transporting and selling oil and natural gas primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations, which are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake-operated wells and wells operated by third parties.

Management evaluates the performance of our segments based upon income before income taxes. Revenues from the marketing segment s sale of oil and natural gas related to Chesapeake s ownership interests are reflected as exploration and production revenues. Such amounts totaled $893 million, $597 million, $1.598 billion and $1.288 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. The following table presents selected financial information for Chesapeake s operating segments. Our drilling rig and trucking service operations are presented in Other Operations .

	Exploration and Production	Marketing	Other Operations ($ in millions)	Intercompany Eliminations	Consolidated Total
For the Three Months Ended June 30, 2007:					
Revenues	$ 1,548	$ 1,416	$ 116	$ (975)	$ 2,105
Intersegment revenues		(893)	(82)	975	
Total revenues	$ 1,548	$ 523	$ 34	$	$ 2,105
Income before income taxes	$ 822	$ 10	$ 36	$ (32)	$ 836
For the Three Months Ended June 30, 2006:					

Revenues	$ 1,186	$ 965	$ 71	$ (638)	$ 1,584
Intersegment revenues		(597)	(41)	638	
Total revenues	$ 1,186	$ 368	$ 30	$	$ 1,584
Income before income taxes	$ 593	$ 8	$ 22	$ (18)	$ 605

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Exploration and Production	Marketing	Other Operations ($ in millions)	Intercompany Eliminations	Consolidated Total
For the Six Months Ended June 30, 2007:					
Revenues	$ 2,672	$ 2,543	$ 224	$ (1,755)	$ 3,684
Intersegment revenues		(1,598)	(157)	1,755	
Total revenues	$ 2,672	$ 945	$ 67	$	$ 3,684
Income before income taxes	$ 1,227	$ 18	$ 66	$ (59)	$ 1,252
For the Six Months Ended June 30, 2006:					
Revenues	$ 2,697	$ 2,060	$ 121	$ (1,349)	$ 3,529
Intersegment revenues		(1,288)	(61)	1,349	
Total revenues	$ 2,697	$ 772	$ 60	$	$ 3,529
Income before income taxes	$ 1,582	$ 19	$ 34	$ (24)	$ 1,611
As of June 30, 2007:					
Total assets	$ 26,421	$ 1,156	$ 795	$ (676)	$ 27,696
As of December 31, 2006:					
Total assets	$ 23,333	$ 864	$ 786	$ (566)	$ 24,417

8. Acquisitions and Investments

Oil and Natural Gas Properties

Through multiple acquisitions completed in the Current Period, we invested $397 million in proved properties and, we invested $1.075 billion in leasehold and unproved property acquisitions, including capitalized interest. Additionally we recorded approximately $101 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions.

Investments

In the Current Quarter, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $126 million and a pre-tax gain of $83 million.

9. Recently Issued and Proposed Accounting Standards

The FASB recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In June 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. We adopted FIN 48 effective January 1, 2007. The effect of FIN 48 is more fully described in Note 1.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments we acquire or issue after December 31, 2006. Adoption of SFAS 155 did not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by this statement permits all entities to choose to measure eligible items at fair value at specified election dates. This statement is effective as of the beginning of the first fiscal year that begins after November 15, 2007. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

The FASB has announced that it plans to issue proposed staff guidance on accounting for convertible debt instruments that may be settled in cash upon conversion, including partial cash settlements. This accounting could increase the amount of interest expense required to be recognized with respect to such instruments and, thus, lower reported net income and net income per share of issuers of such instruments. Issuers would have to account for the liability and equity components of the instrument separately and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. We have two debt series that would be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035 and our 2.5% Contingent Convertible Senior Notes due 2037. If the FASB adopts the guidance, it is expected to be effective for fiscal years starting after December 15, 2007. Companies would have to apply the guidance retrospectively to both existing and new instruments that fall within the scope of the guidance.

10. Subsequent Events

On July 12, 2007, Chesapeake and Anadarko Petroleum Corporation jointly announced the completion of multiple agreements, including a joint venture involving Chesapeake and Anadarko assets in the Deep Haley area of the Delaware Basin in West Texas. Through the formation of a joint venture and other separate agreements, Chesapeake received various interests in Anadarko s existing Deep Haley area production, leasehold and contractual rights as well as Oklahoma City real estate assets acquired by Anadarko in 2006 as part of its acquisition of Kerr-McGee Corporation. Through the formation of the joint venture and other separate agreements, Anadarko received approximately $310 million in cash and other consideration. Subsequently, Chesapeake and SandRidge Energy, Inc. jointly announced the execution of a transaction by which SandRidge acquired from Chesapeake certain downtown Oklahoma City real estate assets that Chesapeake acquired as a part of this transaction.

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PART I. FINANCIAL INFORMATION

ITEM 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

Overview

The following table sets forth certain information regarding the production volumes, oil and natural gas sales, average sales prices received, other operating income and expenses for the three and six months ended June 30, 2007 (the Current Quarter and the Current Period) and the three and six months ended June 30, 2006 (the Prior Quarter and the Prior Period):

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Net Production:				
Oil (mbbls)	2,324	2,143	4,467	4,259
Natural gas (mmcf)	156,080	129,818	296,872	253,874
Natural gas equivalent (mmcfe)	170,024	142,676	323,674	279,428
Oil and Natural Gas Sales ($ in millions):				
Oil sales	$ 140	$ 138	$ 253	$ 263
Oil derivatives realized gains (losses)	12	(12)	30	(16)
Oil derivatives unrealized gains (losses)	(15)	(3)	(27)	(4)
Total oil sales	137	123	256	243
Natural gas sales	1,059	774	1,947	1,714
Natural gas derivatives realized gains (losses)	185	270	600	522
Natural gas derivatives unrealized gains (losses)	167	19	(131)	218
Total natural gas sales	1,411	1,063	2,416	2,454
Total oil and natural gas sales	$ 1,548	$ 1,186	$ 2,672	$ 2,697
Average Sales Price (excluding all gains (losses) on derivatives):				
Oil ($ per bbl)	$ 60.10	$ 64.51	$ 56.60	$ 61.73
Natural gas ($ per mcf)	$ 6.78	$ 5.96	$ 6.56	$ 6.75
Natural gas equivalent ($ per mcfe)	$ 7.05	$ 6.40	$ 6.80	$ 7.08
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$ 65.37	$ 58.80	$ 63.34	$ 57.97
Natural gas ($ per mcf)	$ 7.97	$ 8.04	$ 8.58	$ 8.81
Natural gas equivalent ($ per mcfe)	$ 8.21	$ 8.20	$ 8.74	$ 8.89
Other Operating Income[a] ($ in millions):				
Oil and natural gas marketing	$ 19	$ 12	$ 34	$ 25
Service operations	$ 11	$ 14	$ 23	$ 30
Other Operating Income ($ per mcfe):				
Oil and natural gas marketing	$ 0.11	$ 0.08	$ 0.10	$ 0.09
Service operations	$ 0.07	$ 0.10	$ 0.07	$ 0.10
Expenses ($ per mcfe):				
Production expenses	$ 0.90	$ 0.85	$ 0.91	$ 0.86
Production taxes	$ 0.31	$ 0.24	$ 0.29	$ 0.32
General and administrative expenses	$ 0.32	$ 0.24	$ 0.33	$ 0.22
Oil and natural gas depreciation, depletion and amortization	$ 2.60	$ 2.30	$ 2.58	$ 2.27
Depreciation and amortization of other assets	$ 0.23	$ 0.16	$ 0.23	$ 0.17
Interest expense[b]	$ 0.54	$ 0.51	$ 0.52	$ 0.52
Interest Expense ($ in millions):				

Interest expense	$ 91	$ 73	$ 166	$ 146
Interest rate derivatives realized (gains) losses		(1)	2	(2)
Interest rate derivatives unrealized (gains) losses	(7)	1	(6)	2
Total interest expense	$ 84	$ 73	$ 162	$ 146
Net Wells Drilled	489	329	950	584
Net Producing Wells as of the End of the Period	20,136	18,016	20,136	18,016

(a) Includes revenue and operating costs.

(b) Includes the effects of realized gains (losses) from interest rate derivatives, but excludes the effects of unrealized gains (losses) and is net of amounts capitalized.

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We believe we are the third largest producer of natural gas in the United States (first among independents). We own interests in approximately 36,500 producing oil and natural gas wells that are currently producing approximately 1.975 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S. east of the Rocky Mountains.

Our most important operating area has historically been in various conventional plays in the *Mid-Continent region* of Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle. At June 30, 2007, 48% of our estimated proved oil and natural gas reserves were located in the Mid-Continent region. During the past five years, we have also built significant positions in various conventional and unconventional plays in the *Fort Worth Basin* in north-central Texas; the *Appalachian Basin*, principally in West Virginia, eastern Kentucky, eastern Ohio, Pennsylvania and southern New York; the *Permian and Delaware Basins* of West Texas and eastern New Mexico; the *Ark-La-Tex* area of East Texas and northern Louisiana; and the *South Texas and Texas Gulf Coast regions*. We have established a top-three position in nearly every major unconventional play onshore in the U.S. east of the Rockies, including the Fort Worth Barnett Shale, the Arkansas Fayetteville Shale, the Appalachian Basin Devonian Shale, the southeast Oklahoma Woodford Shale, the Delaware Basin Barnett and Woodford Shales, the Illinois Basin New Albany Shale and the Alabama Conasauga, Floyd and Chattanooga Shales.

Oil and natural gas production for the Current Quarter was 170.0 bcfe, an increase of 27.3 bcfe, or 19% over the 142.7 bcfe produced in the Prior Quarter. We have increased our production for 24 consecutive quarters. During these 24 quarters, Chesapeake s U.S. production has increased 372% for an average compound quarterly growth rate of 7% and an average compound annual growth rate of 30%. In addition to increased oil and natural gas production, the prices we received were slightly higher in the Current Quarter compared to the Prior Quarter. On a natural gas equivalent basis, weighted average prices (excluding the effect of unrealized gains or losses on derivatives) were $8.21 per mcfe in the Current Quarter compared to $8.20 per mcfe in the Prior Quarter. The increased production resulted in an increase in revenue of $224 million and the increase in prices resulted in an increase in revenue of $2 million, for a total increase in revenue of $226 million (excluding the effect of unrealized gains or losses on derivatives). In each of the operating areas where Chesapeake sells its oil and natural gas, established marketing and transportation infrastructures exist, thereby contributing to relatively high wellhead price realizations for our production.

During the Current Quarter, Chesapeake continued to lead the nation in drilling activity with an average utilization of 133 operated rigs and 109 non-operated rigs. Through this drilling activity, we drilled 501 (431 net) operated wells and participated in another 432 (58 net) wells operated by other companies. Our drilling success rate was 99% for company-operated wells and 97% for non-operated wells. During the Current Quarter, Chesapeake invested $1.015 billion in operated wells, $165 million in non-operated wells, $84 million in acquiring 3-D seismic data and $622 million to acquire new leasehold through corporate and asset acquisitions. Our acquisition expenditures for proved properties totaled $237 million during the Current Quarter. Additionally we recorded $94 million of deferred income taxes in connection with certain corporate acquisitions. The shift between our drilling expenditures and acquisition expenditures during the quarter reflects our change in focus from resource inventory capture to resource inventory conversion.

Chesapeake began 2007 with estimated proved reserves of 8.956 tcfe and based on internal estimates ended the Current Quarter with 9.979 tcfe, an increase of 1.023 tcfe, or 11%. During the Current Period, we replaced 324 bcfe of production with an estimated 1.347 tcfe of new proved reserves, for a reserve replacement rate of 416%. Reserve replacement through the drillbit was 1.145 tcfe, or 354% of production (including 510 bcfe of positive performance revisions and 95 bcfe of positive revisions resulting from oil and natural gas price increases between December 31, 2006 and June 30, 2007) and 85% of the total increase. Reserve replacement through the acquisition of proved reserves was 202 bcfe, or 62% of production and 15% of the total increase. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2007 will begin producing within the next three to five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within one year.

Chesapeake attributes its strong drilling results and production growth during the Current Quarter to management s early recognition that oil and natural gas prices were undergoing structural change and its subsequent decision to invest aggressively in the building blocks of value creation in the E&P industry people, land and seismic. During the past five years, Chesapeake has significantly strengthened its technical capabilities by increasing its land, geoscience and engineering staff to over 1,200 employees. Today, the company has approximately 5,800 employees, of which approximately 60% work in the company s E&P operations and 40% work in the company s oilfield service operations.

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Since 2000, Chesapeake has invested $7.8 billion in new leasehold and 3-D seismic acquisitions and now owns the largest combined inventory of onshore leasehold (12.2 million net acres) and 3-D seismic (17.7 million acres) in the U.S. On this leasehold, the company has an estimated 28,500 net drilling locations, representing an approximate 10-year inventory of drilling projects.

As of June 30, 2007, the company s debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 45% compared to 40% as of December 31, 2006. The average maturity of our long-term debt is almost nine years and our average interest rate is approximately 6.0%.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for acquisitions). Cash provided by operating activities was $2.122 billion in the Current Period compared to $2.045 billion in the Prior Period. The $77 million increase in the Current Period was primarily due to higher oil and natural gas production. Changes in cash flow from operations are largely due to the same factors that affect our net income and reflect the impact on earnings of non-cash items, such as depreciation, depletion and amortization ($903 million and $674 million during the Current Period and the Prior Period, respectively), deferred income taxes ($460 million and $627 million during the Current Period and the Prior Period, respectively) and unrealized gains and (losses) on derivatives (($152) million and $212 million during the Current Period and the Prior Period, respectively). Net income decreased to $776 million in the Current Period from $984 million in the Prior Period and is discussed below under *Results of Operations*.

Changes in market prices for oil and natural gas directly impact the level of our cash flow from operations. While a decline in oil or natural gas prices in 2007 would affect the amount of cash flow that would be generated from operations, we currently have oil swaps in place covering 73% of our expected remaining oil production in 2007 at an average NYMEX price of $71.59 per barrel of oil and natural gas swaps in place covering 59% of our expected remaining natural gas production in 2007 at an average NYMEX price of $8.66 per mcf, along with natural gas collars covering 12% of our anticipated remaining natural gas production for 2007 with an average NYMEX floor of $6.94 per mcf and an average NYMEX ceiling of $8.52 per mcf. Additionally, we have written call options covering 15% of our 2007 remaining natural gas production at a weighted average price of $9.45 for a weighted average premium of $0.55 per mcf. This level of hedging provides certainty of the cash flow we will receive for a substantial portion of our 2007 production. Depending on changes in oil and natural gas futures markets and management s view of underlying oil and natural gas supply and demand trends, we may increase or decrease our current hedging positions.

Based on fluctuations in natural gas and oil prices, some of our hedging counterparties may require us to deliver cash collateral or other assurances of performance from time to time. All but two of our commodity price risk management counterparties require us to provide assurances of performance in the event that the counterparties mark-to-market exposure to us exceeds certain levels. Most of these arrangements allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations by making collateral allocations from our bank credit facility or directly pledging oil and natural gas properties, rather than posting cash or letters of credit with the counterparties. As of June 30, 2007 and August 6, 2007, we had outstanding collateral allocations and pledges of oil and natural gas properties with respect to commodity price risk management transactions but were not required to post any other collateral. Future collateral requirements are uncertain and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

We use borrowings under our $2.5 billion revolving bank credit facility to supplement cash flow from operations. At August 6, 2007, there was $453 million of borrowing capacity available under the revolving bank credit facility. We use the facility to fund daily operating activities and acquisitions as needed. We borrowed $3.544 billion and repaid $2.624 billion in the Current Period, and we borrowed $4.055 billion and repaid $4.127 billion in the Prior Period under the credit facility.

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The public and institutional markets provide us additional liquidity and over time have been our principal source of long-term financing for acquisitions. We have sold debt and equity in both public and private offerings in the past, and we expect that these sources of capital will continue to be available to us in the future. Nevertheless, we caution that ready access to capital on reasonable terms is subject to many uncertainties, as explained under Risk Factors in Item 1A of our Form 10-K for the year ended December 31, 2006. The recent volatility in the U.S. securities markets heightens the risk for us that capital might not be available when needed to supplement operating cash flow to fund our budgeted capital expenditures, or might only be available on terms we consider unattractive.

In the Current Quarter, we completed a public offering of $1.15 billion of 2.5% Contingent Convertible Senior Notes due 2037. Net proceeds of approximately $1.124 billion were used to repay outstanding borrowings under our revolving bank credit facility. The following table reflects the proceeds from sales of securities we issued in the Current Period and the Prior Period ($ in millions):

	For the Six Months Ended June 30,			
	2007		2006	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Convertible preferred stock	$	$	$ 500	$ 485
Common stock			726	699
Contingent convertible unsecured senior notes	1,150	1,124		
Unsecured senior notes guaranteed by subsidiaries			1,000	969
Total	$ 1,150	$ 1,124	$ 2,226	$ 2,153

Our primary use of funds is our capital expenditures for exploration and development of oil and natural gas reserves. We refer you to the table under *Investing Activities* below, which sets forth the components of our oil and natural gas investing activities for the Current Period and the Prior Period. Our drilling, land and seismic capital expenditures in 2007 are currently budgeted at $5.1 billion to $5.6 billion and are expected to exceed our 2007 cash flow from operating activities. We believe this level of exploration and development will enable us to increase our proved oil and natural gas reserves in 2007 by more than 15% and increase our total production by 18% to 22% (inclusive of acquisitions completed or scheduled to close in 2007 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2007).

At times during the remainder of 2007 and 2008, we expect our capital expenditures, operating costs, debt service, short-term contractual obligations and dividend payments will exceed our available cash, cash provided by operating activities and funds available under our revolving bank credit facility. We plan to obtain additional liquidity through the sale of a portion of our Appalachian production and proved reserves and the sale and leaseback of drilling rig and compressor assets. We believe these transactions could provide the company more than $1 billion of cash proceeds by year-end 2007. We may also arrange long-term financing by accessing the capital markets.

We retain a significant degree of control over the timing of our capital expenditures which permits us to defer or accelerate certain capital expenditures if necessary to address liquidity issues. In addition, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary.

We paid dividends on our common stock of $54 million and $37 million in the Current Period and the Prior Period, respectively. The board of directors increased the quarterly dividend on common stock from $0.06 to $0.0675 per share beginning with the dividend paid in July 2007. We paid dividends on our preferred stock of $52 million and $38 million in the Current Period and the Prior Period, respectively. We received $6 million and $68 million from the exercise of employee and director stock options in the Current Period and the Prior Period, respectively. The Prior Period amount included $38 million paid by Tom L. Ward, our former President and Chief Operating Officer, to exercise all of his stock options following his resignation in February 2006.

In the Current Period and Prior Period, we paid $52 million and $51 million, respectively, to settle a portion of the derivative liabilities assumed in our November 2005 acquisition of Columbia Natural Resources, LLC.

On January 1, 2006, we adopted SFAS 123(R), which requires tax benefits resulting from stock-based compensation deductions in excess of amounts reported for financial reporting purposes to be reported as cash flows from financing activities. In the Current Period and the Prior Period, we reported a tax benefit from stock-based compensation of $8 million and $81 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists decreased $10 million in the Current Period and increased $42 million in the Prior Period. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facility.

Our accounts receivable are primarily from purchasers of oil and natural gas ($658 million at June 30, 2007) and exploration and production companies which own interests in properties we operate ($135 million at June 30, 2007). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

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Investing Transactions

Cash used in investing activities increased to $4.003 billion during the Current Period, compared to $3.784 billion during the Prior Period. The following table shows our cash used in (provided by) investing activities during these periods ($ in millions):

	Six Months Ended June 30,	
	2007	2006
Oil and Natural Gas Investing Activities:		
Acquisitions of oil and natural gas companies and proved properties, net of cash acquired	$ 327	$ 448
Acquisition of leasehold and unproved properties	1,075	1,580
Exploration and development of oil and natural gas properties	2,185	1,289
Geological and geophysical costs	134	72
Other oil and natural gas activities		4
Total oil and natural gas investing activities	3,721	3,393
Other Investing Activities:		
Additions to buildings and other fixed assets	414	181
Additions to drilling rig equipment	70	244
Proceeds from sale of drilling rigs and equipment	(87)	
Additions to investments	12	38
Proceeds from sale of investments `	(124)	(159)
Acquisition of trucking company, net of cash acquired		45
Deposits for acquisitions	5	43
Sale of non-oil and natural gas assets	(8)	(1)
Total other investing activities	282	391
Total cash used in investing activities	$ 4,003	$ 3,784

Contractual Obligations

We have a $2.5 billion syndicated revolving bank credit facility which matures in February 2011. As of June 30, 2007, we had $1.098 billion in outstanding borrowings under this facility and had utilized approximately $4 million of the facility for various letters of credit. Borrowings under the facility are collateralized by certain producing oil and natural gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A., or the federal funds effective rate plus 0.50% or (ii) London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently the commitment fee is 0.25% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility, our indebtedness to total capitalization ratio was 0.45 to 1 and our indebtedness to EBITDA ratio was 2.00 to 1 at June 30, 2007. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

We have three secured hedging facilities maturing in 2011, each of which permits us to enter into cash-settled oil and natural gas commodity transactions, valued by the counterparty, for up to a maximum value. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. The hedging facilities are subject to a 1% per annum exposure fee, which is assessed quarterly based on the average of the daily negative fair value amounts of the hedges, if any, during the quarter. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate oil and natural gas production volumes that we are permitted to hedge under all of our agreements at any one time. The maximum permitted value of transactions under each facility and the fair values of outstanding transactions are shown below.

	Secured Hedging Facilities		
	#1	#2	#3
	($ in millions)		
Maximum permitted value of transactions under facility	$ 750	$ 500	$ 500
Fair value of outstanding transactions, as of June 30, 2007	$ 11	$ (97)	$ (23)

Two of our subsidiaries, Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake Exploration, L.L.C. is the named party to our hedging facilities. The facilities are guaranteed by Chesapeake and all its other wholly owned subsidiaries except minor subsidiaries. Our revolving bank credit facility and secured hedging facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates and commitment fees in our bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, the bank facility and the secured hedging facilities do not contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

In addition to outstanding revolving bank credit facility borrowings discussed above, as of June 30, 2007, senior notes represented approximately $8.319 billion of our long-term debt and consisted of the following ($ in millions):

7.5% Senior Notes due 2013	$ 364
7.625% Senior Notes due 2013	500
7.0% Senior Notes due 2014	300
7.5% Senior Notes due 2014	300
7.75% Senior Notes due 2015	300
6.375% Senior Notes due 2015	600
6.625% Senior Notes due 2016	600
6.875% Senior Notes due 2016	670
6.5% Senior Notes due 2017	1,100
6.25% Euro-denominated Senior Notes due 2017 (a)	811
6.25% Senior Notes due 2018	600
6.875% Senior Notes due 2020	500
2.75% Contingent Convertible Senior Notes due 2035	690
2.5% Contingent Convertible Senior Notes due 2037	1,150
Discount on senior notes	(97)
Discount for interest rate derivatives	(69)
	$ 8,319

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3520 to 1.00 as of June 30, 2007. See Note 2 of our financial statements for information on our related cross currency swap.

No scheduled principal payments are required under our senior notes until 2013, when $864 million is due. The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of the notes. The holders of the 2.5% Contingent Convertible Senior Notes due 2037 may require us to repurchase all or a portion of these notes on May 15, 2017, 2022, 2027 and 2032 at 100% of the principal amount of the notes.

As of June 30, 2007 and currently, debt ratings for the senior notes are Ba2 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (positive outlook) and BB by Fitch Ratings (stable outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment with all of our future subordinated indebtedness. All of our wholly-owned subsidiaries, except minor subsidiaries, fully and unconditionally guarantee the notes jointly and severally on an unsecured basis. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale-leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of June 30, 2007, we estimate that secured commercial bank indebtedness of approximately $3.6 billion could have been incurred under the most restrictive indenture covenant.

As a result of the CNR acquisition, we assumed a collective bargaining agreement with the United Steel Workers of America (USWA) which expired effective December 1, 2006, covering approximately 135 of our field employees in West Virginia. We have continued to operate under the terms of the collective bargaining agreement while negotiating with the USWA. Contract negotiations began in October 2006 and have been mediated by the National Mediation Board. On May 4, 2007, we presented the USWA leadership our last, best and final offer . There have been no strikes, work stoppages or slowdowns since the expiration of the contract, although no assurances can be given that such actions will not occur. Additionally, we can provide no assurance that our last, best and final offer will be voted on by the USWA membership.

Results of Operations Three Months Ended June 30, 2007 vs. June 30, 2006

General. For the Current Quarter, Chesapeake had net income of $518 million, or $1.01 per diluted common share, on total revenues of $2.105 billion. This compares to net income of $360 million, or $0.82 per diluted common share, on total revenues of $1.584 billion during the Prior Quarter.

Oil and Natural Gas Sales. During the Current Quarter, oil and natural gas sales were $1.548 billion compared to $1.186 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 170.0 bcfe at a weighted average price of $8.21 per mcfe, compared to 142.7 bcfe produced in the Prior Quarter at a weighted average price of $8.20 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of $152 million and $16 million in the Current Quarter and Prior Quarter, respectively). In the Current Quarter, the increase in prices resulted in an increase in revenue of $2 million and increased production resulted in a $224 million increase, for a total increase in revenues of $226 million (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from the Prior Quarter to the Current Quarter is due to the combination of production growth generated from drilling as well as acquisitions completed in 2006 and 2007.

For the Current Quarter, we realized an average price per barrel of oil of $65.37, compared to $58.80 in the Prior Quarter (weighted average prices for both quarters discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $7.97 and $8.04 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $197 million, or $1.16 per mcfe, in the Current Quarter and $258 million, or $1.80 per mcfe, in the Prior Quarter.

Changes in oil and natural gas prices have a significant impact on our oil and natural gas revenues and cash flow. Assuming the Current Quarter production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $16 million and $15 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $2 million without considering the effect of derivative activities.

The following table shows our production by region for the Current Quarter and the Prior Quarter:

	For the Three Months Ended June 30,			
	2007		2006	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	91,134	54%	78,208	55%
Fort Worth Barnett Shale	19,046	11	9,912	7
Appalachian Basin	11,493	7	11,225	8
Permian and Delaware Basins	14,540	8	12,707	8
Ark-La-Tex	13,927	8	11,267	8
South Texas and Texas Gulf Coast	19,884	12	19,357	14
Total production	170,024	100%	142,676	100%

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in the Current Quarter, compared to 91% in the Prior Quarter.

Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing sales and operating expenses are from third parties that are owners in Chesapeake-operated wells. Chesapeake recognized $523 million in oil and natural gas marketing sales in the Current Quarter, with corresponding oil and natural gas marketing expenses of $504 million, for a net margin before depreciation of $19 million. This compares to sales of $368 million, expenses of $356 million and a net margin before depreciation of $12 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in oil and natural gas marketing sales volumes related to the increase in production on Chesapeake-operated wells.

Service Operations Revenue and Operating Expenses. Service operations revenue and expenses consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of businesses we acquired and built in 2006. Chesapeake recognized $34 million in service operations revenue in the Current Quarter with corresponding service operations expense of $23 million, for a net margin before depreciation of $11 million. This compares to revenue of $30 million, expenses of $16 million and a net margin before depreciation of $14 million in the Prior Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $153 million in the Current Quarter compared to $120 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.90 per mcfe in the Current Quarter compared to $0.85 per mcfe in the Prior Quarter. The increase in the Current Quarter was primarily due to higher third-party field service costs, energy costs, fuel costs, ad valorem taxes and personnel costs. We expect that production expenses for 2007 will range from $0.90 to $1.00 per mcfe produced.

Production Taxes. Production taxes were $53 million in the Current Quarter compared to $34 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.31 per mcfe in the Current Quarter compared to $0.24 per mcfe in the Prior Quarter. The Prior Quarter included the reversal of an accrual of $12 million as a result of the dismissal of certain production tax claims. Excluding this item, production taxes increased $7 million and were $0.32 per mcfe in the Prior Quarter. The $7 million increase in is due primarily to a price increase of approximately $0.65 per mcfe (excluding gains or losses on derivatives) and an increase in production of 27.3 bcfe.

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and natural gas prices are higher. We expect production taxes for 2007 to range from $0.35 to $0.40 per mcfe based on NYMEX prices of $63.30 per barrel of oil and natural gas wellhead prices ranging from $6.90 to $8.00 per mcf.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our oil and natural gas properties, were $54 million in the Current Quarter and $34 million in the Prior Quarter. General and administrative expenses were $0.32 and $0.24 per mcfe for the Current Quarter and Prior Quarter, respectively. The increase in the Current Quarter was the result of the company s overall growth as well as cost and wage inflation. Included in general and administrative expenses is stock-based compensation of $12 million and $7 million for the Current Quarter and Prior Quarter, respectively. This increase was mainly due to a higher number of unvested restricted shares outstanding during the Current Quarter. We anticipate that general and administrative expenses for 2007 will be between $0.33 and $0.40 per mcfe produced (including stock-based compensation ranging from $0.08 to $0.10 per mcfe).

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Prior to 2005, stock-based compensation awards were in the form of stock options. Employee stock-based compensation awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years.

The discussion of stock-based compensation in Note 1 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our stock options and restricted stock.

Chesapeake follows the full-cost method of accounting under which all costs associated with oil and natural gas property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $59 million and $34 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our oil and natural gas property acquisition, exploration and development efforts.

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Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was $442 million and $328 million during the Current Quarter and the Prior Quarter, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $2.60 and $2.30 in the Current Quarter and in the Prior Quarter, respectively. The $0.30 increase in the average DD&A rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of the tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for 2007 to be between $2.40 and $2.60 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $40 million in the Current Quarter, compared to $23 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of higher depreciation costs resulting from the acquisition of various gathering facilities, compression equipment and drilling rig equipment, the construction of new buildings at our corporate headquarters complex and at various field office locations and the purchase of additional information technology equipment and software in 2006 and the Current Quarter. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent company-owned drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect 2007 depreciation and amortization of other assets to be between $0.24 and $0.28 per mcfe produced.

Interest and Other Income. Interest and other income was $1 million in the Current Quarter compared to $5 million in the Prior Quarter. The Current Quarter income consisted of $2 million of interest income, ($2) million related to earnings of equity investees and $1 million of miscellaneous income. The Prior Quarter income consisted of $1 million of interest income, $2 million related to earnings of equity investees and $2 million of miscellaneous income.

Interest Expense. Interest expense increased to $84 million in the Current Quarter compared to $73 million in the Prior Quarter as follows:

	Three Months Ended June 30,	
	2007	2006
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 147	$ 110
Capitalized interest	(61)	(39)
Realized (gain) loss on interest rate derivatives		(1)
Unrealized (gain) loss on interest rate derivatives	(7)	1
Amortization of loan discount and other	5	2
Total interest expense	$ 84	$ 73
Average long-term borrowings	$ 7,899	$ 6,150

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.54 per mcfe in the Current Quarter compared to $0.51 per mcfe in the Prior Quarter. We expect interest expense for 2007 to be between $0.60 and $0.65 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investments. In the Current Quarter, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $126 million and a gain of $83 million.

Income Tax Expense. Chesapeake recorded income tax expense of $318 million in the Current Quarter, compared to income tax expense of $245 million in the Prior Quarter. Our effective income tax rate was 38% in the Current Quarter compared to 40.5% in the Prior Quarter. The Prior Quarter included a $15 million adjustment in additional deferred income taxes related to the effect of Texas House Bill 3 which was signed into law in May 2006. Excluding the effect of this adjustment, our effective income tax rate was 38% for the Prior Quarter. Most of our 2006 income tax expense was deferred, and we expect most of our 2007 income tax expense to be deferred.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $10 million in the Prior Quarter. The loss represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms.

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Results of Operations Six Months Ended June 30, 2007 vs. June 30, 2006

General. For the Current Period, Chesapeake had net income of $776 million, or $1.51 per diluted common share, on total revenues of $3.684 billion. This compares to net income of $984 million, or $2.27 per diluted common share, on total revenues of $3.529 billion during the Prior Period.

Oil and Natural Gas Sales. During the Current Period, oil and natural gas sales were $2.672 billion compared to $2.697 billion in the Prior Period. In the Current Period, Chesapeake produced 323.7 bcfe at a weighted average price of $8.74 per mcfe, compared to 279.4 bcfe produced in the Prior Period at a weighted average price of $8.89 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of ($158) million and $214 million in the Current Period and Prior Period, respectively). In the Current Period, the decrease in prices resulted in a decrease in revenue of $46 million and increased production resulted in a $393 million increase, for a total increase in revenues of $347 million (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from the Prior Period to the Current Period is due to the combination of production growth generated from drilling as well as acquisitions completed in 2006 and the Current Period.

For the Current Period, we realized an average price per barrel of oil of $63.34, compared to $57.97 in the Prior Period (weighted average prices for both quarters discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $8.58 and $8.81 in the Current Period and Prior Period, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $630 million, or $1.95 per mcfe, in the Current Period and $506 million, or $1.81 per mcfe, in the Prior Period.

Changes in oil and natural gas prices have a significant impact on our oil and natural gas revenues and cash flow. Assuming the Current Period production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $30 million and $28 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $4 million without considering the effect of derivative activities.

The following table shows our production by region for the Current Period and the Prior Period:

	For the Six Months Ended June 30,			
	2007		2006	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	172,838	53%	152,132	55%
Fort Worth Barnett Shale	35,201	11	18,477	7
Appalachian Basin	22,573	7	21,518	8
Permian and Delaware Basins	27,248	9	24,801	8
Ark-La-Tex	26,787	8	22,881	8
South Texas and Texas Gulf Coast	39,027	12	39,619	14
Total production	323,674	100%	279,428	100%

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in the Current Period, compared to 91% in the Prior Period.

Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing sales and operating expenses are from third parties that are owners in Chesapeake-operated wells. Chesapeake recognized $945 million in oil and natural gas marketing sales in the Current Period, with corresponding oil and natural gas marketing expenses of $911 million, for a net margin before depreciation of $34 million. This compares to sales of $772 million, expenses of $747 million and a net margin before depreciation of $25 million in the Prior Period. In the Current Period, Chesapeake realized an increase in oil and natural gas marketing sales volumes related to the increase in production on Chesapeake-operated wells.

Service Operations Revenue and Operating Expenses. Service operations revenue and expenses consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of businesses we acquired and built in 2006. Chesapeake recognized $67 million in service operations revenue in the Current Period with corresponding service operations expense of $44 million, for a net margin before depreciation of $23 million. This compares to revenue of $60 million, expenses of $30 million and a net margin before depreciation of $30 million in the Prior Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $295 million in the Current Period compared to $240 million in the Prior Period. On a unit-of-production basis, production expenses were $0.91 per mcfe in the Current Period compared to $0.86 per mcfe in the Prior Period. The increase in the Current Period was primarily due to higher third-party field service costs, energy costs, fuel costs, ad valorem taxes and personnel costs. We expect that production expenses for 2007 will range from $0.90 to $1.00 per mcfe produced.

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Production Taxes. Production taxes were $95 million in the Current Period compared to $89 million in the Prior Period. On a unit-of-production basis, production taxes were $0.29 per mcfe in the Current Period compared to $0.32 per mcfe in the Prior Period. The Prior Period included a $2 million accrual for certain severance tax claims and then a subsequent reversal of the cumulative $12 million accrual for such severance tax claims as a result of their dismissal. After adjusting for these items, there was a decrease of $4 million in production taxes from the Prior Period. The $4 million decrease is due to a price decrease of approximately $0.28 per mcfe (excluding gains or losses on derivatives) and an increase in qualified production tax exemptions in Texas partially offset by an increase in production of 44.2 bcfe.

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and natural gas prices are higher. We expect production taxes for 2007 to range from $0.35 to $0.40 per mcfe based on NYMEX prices of $63.30 per barrel of oil and natural gas wellhead prices ranging from $6.90 to $8.00 per mcf.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our oil and natural gas properties, were $107 million in the Current Period and $63 million in the Prior Period. General and administrative expenses were $0.33 and $0.22 per mcfe for the Current Period and Prior Period, respectively. The increase in the Current Period was the result of the company s overall growth as well as cost and wage inflation. Included in general and administrative expenses is stock-based compensation of $22 million and $13 million for the Current Period and Prior Period, respectively. This increase was mainly due to a higher number of unvested restricted shares outstanding during the Current Period. We anticipate that general and administrative expenses for 2007 will be between $0.33 and $0.40 per mcfe produced (including stock-based compensation ranging from $0.08 to $0.10 per mcfe).

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Prior to 2005, stock-based compensation awards were in the form of stock options. Employee stock-based compensation awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years.

The discussion of stock-based compensation in Note 1 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our stock options and restricted stock.

Chesapeake follows the full-cost method of accounting under which all costs associated with oil and natural gas property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $110 million and $69 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our oil and natural gas property acquisition, exploration and development efforts.

Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was $835 million and $633 million during the Current Period and the Prior Period, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $2.58 and $2.27 in the Current Period and in the Prior Period, respectively. The $0.31 increase in the average DD&A rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of the tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for 2007 to be between $2.40 and $2.60 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $76 million in the Current Period, compared to $47 million in the Prior Period. The increase in the Current Period was primarily the result of higher depreciation costs resulting from the acquisition of various gathering facilities, compression equipment and drilling rig equipment, the construction of new buildings at our corporate headquarters complex and at various field office locations and the purchase of additional information technology equipment and software in 2006 and the Current Period. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent company-owned drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect depreciation and amortization of other assets for 2007 to be between $0.24 and $0.28 per mcfe produced.

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Employee Retirement Expense. Our former President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward s Resignation Agreement provided for the immediate vesting of all of his unvested equity awards, which consisted of options to purchase 724,615 shares of Chesapeake s common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock. As a result of this vesting, we incurred an expense of $55 million in the Prior Period.

Interest and Other Income. Interest and other income was $10 million in the Current Period compared to $15 million in the Prior Period. The Current Period income consisted of $4 million of interest income, $4 million related to earnings of equity investees and $2 million of miscellaneous income. The Prior Period income consisted of $1 million of interest income, $7 million related to earnings of equity investees, a $4 million gain on sale of assets and $3 million of miscellaneous income.

Interest Expense. Interest expense increased to $162 million in the Current Period compared to $146 million in the Prior Period as follows:

	Six Months Ended June 30,	
	2007	2006
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 282	$ 213
Capitalized interest	(125)	(70)
Realized (gain) loss on interest rate derivatives	2	(2)
Unrealized (gain) loss on interest rate derivatives	(6)	2
Amortization of loan discount and other	9	3
Total interest expense	$ 162	$ 146
Average long-term borrowings	$ 7,653	$ 5,953

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.52 per mcfe for both the Current Period and the Prior Period. We expect interest expense for 2007 to be between $0.60 and $0.65 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investments. In the Current Period, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003 for proceeds of $126 million and a gain of $83 million. In the Prior Period, Chesapeake sold its investment in publicly-traded Pioneer Drilling Company common stock, realizing proceeds of $159 million and a gain of $117 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

Income Tax Expense. Chesapeake recorded income tax expense of $476 million in the Current Period, compared to income tax expense of $627 million in the Prior Period. Our effective income tax rate was 38% in the Current Period compared to 38.9% in the Prior Period. The Prior Period included a $15 million adjustment in additional deferred income taxes related to the effect of Texas House Bill 3 which was signed into law in May 2006. Excluding the effect of this adjustment, our effective income tax rate was 38% for the Prior Period. Most of our 2006 income tax expense was deferred, and we expect most of our 2007 income tax expense to be deferred.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $11 million in the Prior Period. The loss represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms.

Critical Accounting Policies

We consider accounting policies related to hedging, oil and natural gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2006.

Recently Issued and Proposed Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In June 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. We adopted FIN 48 effective January 1, 2007. The effect of FIN 48 is more fully discussed in Note 1 of our financial statements included in Part I of this report.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. SFAS 155 did not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by this statement permits all entities to choose to measure eligible items at fair value at specified election dates. This statement is effective as of the beginning of the first fiscal year that begins after November 15, 2007. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

The FASB has announced that it plans to issue proposed staff guidance on accounting for convertible debt instruments that may be settled in cash upon conversion, including partial cash settlements. This accounting could increase the amount of interest expense required to be recognized with respect to such instruments and, thus, lower reported net income and net income per share of issuers of such instruments. Issuers would have to account for the liability and equity components of the instrument separately and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. We have two debt series that would be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035 and our 2.5% Contingent Convertible Senior Notes due 2037. If the FASB adopts the guidance, it is expected to be effective for fiscal years starting after December 15, 2007. Companies would have to apply the guidance retrospectively to both existing and new instruments that fall within the scope of the guidance.

Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and natural gas reserve estimates, planned capital expenditures, the drilling of oil and natural gas wells and future acquisitions, expected oil and natural gas production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations and expected future expenses. Statements concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under Risk Factors in Item 1A of our annual report on Form 10-K for the year ended December 31, 2006 and include:

- the volatility of oil and natural gas prices,
- the availability of capital on an economic basis to fund our drilling program,
- our ability to replace reserves and sustain production,

our level of indebtedness,

the strength and financial resources of our competitors,

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uncertainties inherent in estimating quantities of oil and natural gas reserves and projecting future rates of production and the timing of development expenditures,

uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities,

inability to effectively integrate and operate acquired companies and properties,

unsuccessful exploration and development drilling,

declines in the value of our oil and natural gas properties resulting in ceiling test write-downs,

lower prices realized on oil and natural gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities,

lower oil and natural gas prices negatively affecting our ability to borrow,

drilling and operating risks,

adverse effects of governmental regulation, and

losses possible from pending or future litigation.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this report and our other filings with the Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect our business.

ITEM 3. ***Quantitative and Qualitative Disclosures About Market Risk***

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of June 30, 2007, our oil and natural gas derivative instruments were comprised of swaps, knockout swaps, cap-swaps, basis protection swaps, call options, collars and three-way collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty.

For knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

For call options, Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

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Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

A three-way collar contract consists of a standard collar contract plus a written put option with a strike price below the floor price of the collar. In addition to the settlement of the collar, the put option requires us to make a payment to the counterparty equal to the difference between the put option price and the settlement price if the settlement price for any settlement period is below the put option strike price.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. Generally, at the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural gas sales in the month of related production.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap. Changes in the value of cap-swaps and counter-swaps are recorded as adjustments to oil and natural gas sales.

In accordance with FASB Interpretation No. 39, to the extent that a legal right of setoff exists, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets.

Gains or losses from certain derivative transactions are reflected as adjustments to oil and natural gas sales on the condensed consolidated statements of operations. Realized gains (losses) are included in oil and natural gas sales in the month of related production. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within oil and natural gas sales. Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales as unrealized gains (losses). The components of oil and natural gas sales for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively are presented below.

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
	($ in millions)			
Oil and natural gas sales	$ 1,199	$ 912	$ 2,200	$ 1,977
Realized gains on oil and natural gas derivatives	197	258	630	506
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	162	(49)	(94)	49
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(10)	65	(64)	165
Total oil and natural gas sales	$ 1,548	$ 1,186	$ 2,672	$ 2,697

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As of June 30, 2007, we had the following open oil and natural gas derivative instruments (excluding derivatives assumed through our acquisition of CNR in November 2005) designed to hedge a portion of our oil and natural gas production for periods after June 2007:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at June 30, 2007 ($ in millions)
Natural Gas (mmbtu):								
Swaps:								
3Q 2007	25,260,000	$ 7.29	$	$	$	Yes	$	$ 11
4Q 2007	40,570,000	8.18				Yes		11
1Q 2008	64,382,500	10.01				Yes		74
2Q 2008	51,642,500	8.34				Yes		23
3Q 2008	52,210,000	8.40				Yes		16
4Q 2008	50,990,000	9.02				Yes		14
Basis Protection Swaps (Mid-Continent):								
3Q 2007	48,300,000				(0.47)	No		20
4Q 2007	40,370,000				(0.37)	No		31
1Q 2008	33,215,000				(0.30)	No		29
2Q 2008	26,845,000				(0.25)	No		21
3Q 2008	27,140,000				(0.25)	No		18
4Q 2008	31,410,000				(0.28)	No		24
1Q 2009	26,100,000				(0.32)	No		18
2Q 2009	20,020,000				(0.28)	No		5
3Q 2009	20,240,000				(0.28)	No		5
4Q 2009	20,240,000				(0.28)	No		7
2Q 2012	4,550,000				(0.34)	No		
3Q 2012	4,600,000				(0.34)	No		
4Q 2012	1,550,000				(0.34)	No		
Basis Protection Swaps (Appalachian Basin):								
3Q 2007	9,200,000				0.35	No		
4Q 2007	9,200,000				0.35	No		
1Q 2008	10,920,000				0.35	No		(1)
2Q 2008	10,920,000				0.35	No		
3Q 2008	11,040,000				0.35	No		
4Q 2008	11,040,000				0.35	No		
1Q 2009	9,000,000				0.31	No		(1)
2Q 2009	9,100,000				0.31	No		
3Q 2009	9,200,000				0.31	No		
4Q 2009	9,200,000				0.31	No		
1Q 2010	7,200,000				0.31	No		(1)
2Q 2010	7,280,000				0.31	No		
3Q 2010	7,360,000				0.31	No		
4Q 2010	7,360,000				0.31	No		
1Q 2011	5,400,000				0.31	No		(1)
2Q 2011	5,460,000				0.31	No		
3Q 2011	5,520,000				0.31	No		
4Q 2011	5,520,000				0.31	No		
Knockout Swaps:								
3Q 2007	63,470,000	8.49	5.95			No		70

4Q 2007	54,640,000	9.31	5.96	No	30
1Q 2008	45,500,000	10.51	6.06	No	32
2Q 2008	60,970,000	9.21	6.22	No	11
3Q 2008	61,640,000	9.32	6.22	No	(3)
4Q 2008	54,320,000	9.92	6.21	No	(6)
1Q 2009	30,600,000	10.36	6.23	No	(6)
2Q 2009	28,210,000	8.73	6.25	No	(10)
3Q 2009	28,520,000	8.87	6.25	No	(13)
4Q 2009	28,520,000	9.44	6.25	No	(14)

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	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at June 30, 2007 ($ in millions)
Call Options:								
3Q 2007	23,270,000	$	$	$ 9.26		No	$ 11	$ (2)
4Q 2007	27,900,000			9.60		No	17	(15)
1Q 2008	28,210,000			10.24		No	21	(26)
2Q 2008	25,480,000			10.44		No	17	(9)
3Q 2008	25,760,000			10.44		No	17	(15)
4Q 2008	24,540,000			10.46		No	16	(24)
1Q 2009	19,800,000			11.34		No	11	(22)
2Q 2009	17,290,000			11.39		No	10	(6)
3Q 2009	17,480,000			11.39		No	9	(8)
4Q 2009	17,480,000			11.39		No	9	(14)
Collars:								
3Q 2007	2,760,000		7.00	8.35		Yes		1
4Q 2007	5,810,000		7.26	9.06		Yes		
1Q 2008	7,590,000		7.32	9.17		Yes		(5)
2Q 2008	2,730,000		7.50	9.68		Yes		1
3Q 2008	2,760,000		7.50	9.68		Yes		
4Q 2008	2,760,000		7.50	9.68		Yes		(1)
Three-Way Collars:								
3Q 2007	19,320,000		6.73/5.07	8.18		No		4
4Q 2007	13,830,000		7.08/5.28	8.80		No		(1)
1Q 2008	10,920,000		7.40/5.46	9.35		No		(7)
1Q 2009	4,500,000		7.50/6.00	10.72		No		(4)
2Q 2009	4,550,000		7.50/6.00	10.72		No		1
3Q 2009	4,600,000		7.50/6.00	10.72		No		
4Q 2009	4,600,000		7.50/6.00	10.72		No		(2)
Total Natural Gas							138	260
Oil (bbls):								
Swaps:								
3Q 2007	920,000	69.24				Yes		(2)
4Q 2007	920,000	68.85				Yes		(2)
1Q 2008	910,000	70.37				Yes		(2)
2Q 2008	910,000	70.04				Yes		(2)
3Q 2008	920,000	69.69				Yes		(3)
4Q 2008	828,000	68.89				Yes		(3)
1Q 2009	45,000	66.64				Yes		
2Q 2009	45,500	66.27				Yes		
3Q 2009	46,000	65.92				Yes		
4Q 2009	46,000	65.56				Yes		
Knockout Swaps:								
3Q 2007	368,000	70.63	55.00			No		
4Q 2007	368,000	71.43	55.00			No		(1)
1Q 2008	455,000	74.58	53.50			No		
2Q 2008	455,000	74.88	52.50			No		(1)
3Q 2008	460,000	75.08	52.50			No		(1)
4Q 2008	644,000	76.76	54.64			No		(1)

1Q 2009	675,000	78.22	55.00	No	(1)
2Q 2009	682,500	78.35	55.00	No	(1)
3Q 2009	690,000	78.40	55.00	No	(1)
4Q 2009	690,000	78.40	55.00	No	(1)
Cap-Swaps:					
3Q 2007	368,000	78.53	56.25	No	3
4Q 2007	368,000	78.53	56.25	No	2
1Q 2008	273,000	77.60	55.00	No	1
2Q 2008	273,000	77.60	55.00	No	1
3Q 2008	276,000	77.60	55.00	No	1
4Q 2008	276,000	77.60	55.00	No	1

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	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at June 30, 2007 ($ in millions)
Call Options:								
1Q 2008	182,000	$	$	$ 75.00		No	$ 1	$ (1)
2Q 2008	182,000			75.00		No	1	(1)
3Q 2008	184,000			75.00		No	1	(1)
4Q 2008	368,000			75.00		No	2	(2)
1Q 2009	360,000			75.00		No	2	(3)
2Q 2009	364,000			75.00		No	2	(3)
3Q 2009	368,000			75.00		No	2	(3)
4Q 2009	368,000			75.00		No	2	(3)
Total Oil							13	(30)
Total Natural Gas and Oil							$ 151	$ 230

In 2006 and 2007, Chesapeake lifted a portion of its 2007, 2008 and 2009 hedges and as a result has approximately $350 million of deferred hedging gains as of June 30, 2007. These gains have been recorded in accumulated other comprehensive income or as an unrealized gain in oil and natural gas sales. For amounts originally recorded in other comprehensive income, the gain will be recognized in oil and natural gas sales in the month of the hedged production.

We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

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The following details the assumed CNR derivatives remaining as of June 30, 2007:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at June 30, 2007 ($ in millions)
Natural Gas (mmbtu):						
Swaps:						
3Q 2007	10,580,000	$ 4.82	$	$	Yes	$ (21)
4Q 2007	10,580,000	4.82			Yes	(31)
1Q 2008	9,555,000	4.68			Yes	(39)
2Q 2008	9,555,000	4.68			Yes	(29)
3Q 2008	9,660,000	4.68			Yes	(31)
4Q 2008	9,660,000	4.66			Yes	(37)
1Q 2009	4,500,000	5.18			Yes	(18)
2Q 2009	4,550,000	5.18			Yes	(12)
3Q 2009	4,600,000	5.18			Yes	(12)
4Q 2009	4,600,000	5.18			Yes	(14)
Collars:						
1Q 2009	900,000		4.50	6.00	Yes	(3)
2Q 2009	910,000		4.50	6.00	Yes	(2)
3Q 2009	920,000		4.50	6.00	Yes	(2)
4Q 2009	920,000		4.50	6.00	Yes	(2)
Total Natural Gas						$ (253)

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties and subsequently evaluated internally using established index prices and other sources. The actual contribution to our future results of operations will be based on the market prices at the time of settlement and may be more or less than the fair value estimates used at June 30, 2007.

Based upon the market prices at June 30, 2007, we expect to transfer approximately $178 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of June 30, 2007 are expected to mature by December 31, 2012.

Additional information concerning the fair value of our oil and natural gas derivative instruments, including CNR derivatives assumed, is as follows:

	2007 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ 345
Change in fair value of contracts during the period	442
Fair value of contracts when entered into during the period	(145)
Contracts realized or otherwise settled during the period	(630)
Fair value of contracts when closed during the period	(35)
Fair value of contracts outstanding, as of June 30	$ (23)

The change in the fair value of our derivative instruments since January 1, 2007 resulted from the settlement of derivatives for a realized gain, as well as an increase in natural gas prices. Derivative instruments reflected as current in the condensed consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and natural gas as of the condensed consolidated balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

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Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of June 30, 2007, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity							
	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value
	($ in billions)							
Liabilities:								
Long-term debt - fixed-rate[(a)]	$	$	$	$	$	$ 8.485	$ 8.485	$ 8.417
Average interest rate						6.0%	6.0%	6.0%
Long-term debt - variable rate	$	$	$	$	$ 1.098	$	$ 1.098	$ 1.098
Average interest rate					6.8%		6.8%	6.8%

(a) This amount does not include the discount included in long-term debt of ($97) million and the discount for interest rate swaps of ($69) million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving bank credit facility. All of our other long-term indebtedness is fixed rate and, therefore, does not expose us to the risk of earnings or cash flow loss due to changes in market interest rates. However, changes in interest rates do affect the fair value of our debt.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the condensed consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from certain derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. Realized gains (losses) included in interest expense were less than ($1) million, $1 million, ($2) million and $2 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were $7 million, ($1) million, $6 million and ($2) million, in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

As of June 30, 2007, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value ($ in millions)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (4)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	(9)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	(9)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(12)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	(7)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	(13)

December 2006	July 2013	$ 250,000,000	7.625%	6 month LIBOR plus 266.5 basis points		(8)
January 2007	July 2013	$ 250,000,000	7.625%	6 month LIBOR plus 251 basis points		(6)
February 2007	August 2017	$ 250,000,000	6.500%	6 month LIBOR plus 124.5 basis points		(8)
June 2007	January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 40.3 basis points		(4)
June 2007	June 2015	$ 250,000,000	6.375%	6 month LIBOR plus 68.25 basis points		(3)
June 2007	November 2020	$ 250,000,000	6.875%	6 month LIBOR plus 132 basis points		(4)
					$	(87)

In the Current Period, we sold call options on three of our interest rate swaps above and received $5 million in premiums. One of the options expired unexercised in the Current Quarter.

In the Current Period, we closed two interest rate swaps for a gain totaling $4 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties will pay Chesapeake 19 million and Chesapeake will pay the counterparties $30 million, which will yield an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($811 million at June 30, 2007) using an exchange rate of $1.3520 to 1.00. The fair value of the cross currency swap is recorded on the consolidated balance sheet as a liability of $13 million at June 30, 2007. The translation adjustment to notes payable is completely offset by the fair value of the cross currency swap and therefore there is no impact to the consolidated statement of operations. The remaining value of the cross currency swap related to future interest payments is reported in other comprehensive income.

ITEM 4. ***Controls and Procedures***

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. At the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake s disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective.

No changes in Chesapeake s internal control over financial reporting occurred during the Current Quarter that have materially affected, or are reasonably likely to materially affect, Chesapeake s internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

Chesapeake is currently involved in various disputes incidental to its business operations. Certain legal actions brought by royalty owners are discussed in Item 3 of our annual report on Form 10-K for the year ended December 31, 2006. Reference also is made to Litigation in Note 3 of the notes to the condensed consolidated financial statements included in Part I, Item 1 of this Form 10-Q, which is incorporated herein by reference. Management is of the opinion that the final resolution of currently pending or threatened litigation is not likely to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 1A. ***Risk Factors***

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock, preferred stock or senior notes are described under Risk Factors in Item 1A of our annual report on Form 10-K for the year ended December 31, 2006. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

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

The following table presents information about repurchases of our common stock during the three months ended June 30, 2007:

Period	Total Number of Shares Purchased [a]	Average Price Paid Per Share [a]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[b]
April 1, 2007 through April 30, 2007	3,887	$ 33.683		
May 1, 2007 through May 31, 2007	8,957	34.862		
June 1, 2007 through June 30, 2007	10,513	34.699		
Total	23,357	$ 34.593		

(a) Includes the deemed surrender to the company of 2,756 shares of common stock to pay the exercise price in connection with the exercise of employee stock options and the surrender to the company of 20,601 shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) We make matching contributions to our 401(k) plan and 401(k) make-up plan using Chesapeake common stock which is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of company contributions.

Item 3. ***Defaults Upon Senior Securities***

Not applicable.

Item 4. ***Submission of Matters to a Vote of Security Holders***

Three matters were submitted to a vote of the shareholders at Chesapeake s annual meeting of shareholders held on June 8, 2007: 1) the election of directors for three year terms expiring in 2010; 2) approval of an amendment to the company s Long Term Incentive Plan covering awards of stock-based compensation to its employees, consultants and non-employee directors and 3) approval of an amendment to the company s 2003 Stock Award Plan for Non-Employee Directors covering awards of common stock to new non-employee directors upon their appointment to the company s Board of Directors.

In the election of directors, Frank Keating received 353,093,786 votes for election and 51,653,249 votes were withheld from voting for Governor Keating; Frederick B. Whittemore received 356,978,547 votes for election and 47,768,488 votes were withheld from voting for Mr. Whittemore; and Merrill A. Miller, Jr. received 399,100,772 votes for election and 5,646,263 votes were withheld from voting for Mr. Miller. There were no broker non-votes for the election of directors. The other directors whose terms continue after the meeting are Don Nickles and Aubrey K. McClendon, whose terms expire in 2008, and Breene M. Kerr, Charles T. Maxwell and Richard K. Davidson, whose terms expire in 2009.

On the proposal to approve an amendment of the Long Term Incentive Plan, 250,101,063 votes were received for approval of the amendment, 45,064,204 votes were received against approval of the amendment and holders of 3,010,644 shares abstained from voting on this proposal. There were 106,571,122 broker non-votes on this proposal.

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On the proposal to approve an amendment of the 2003 Stock Award Plan for Non-Employee Directors, 264,690,650 votes were received for approval of the amendment, 30,441,352 votes were received against approval of the amendment and holders of 3,068,985 shares abstained from voting on this proposal. There were 106,546,046 broker non-votes on this proposal.

Item 5. ***Other Information***

Not applicable.

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Item 6. ***Exhibits***

The following exhibits are filed as a part of this report:

Exhibit Number	Description
3.1.1	Restated Certificate of Incorporation, as amended. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.2	Certificate of Designation for Series A Junior Participating Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.3	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.3 to Chesapeake s Form 10-Q for the quarter ended March 31, 2007.
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B). Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed November 9, 2005.
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended. Incorporated herein by reference to Exhibit 3.1.6 to Chesapeake s Form 10-Q for the quarter ended March 31, 2005.
3.1.6	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed September 15, 2005.
3.1.7	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K dated June 30, 2006.
3.2	Chesapeake s Amended and Restated Bylaws. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed June 13, 2007.
4.1.1*	Tenth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2014.
4.2.1*	Tenth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.
4.3.1*	Fourteenth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.75% senior notes due 2015.
4.6.1*	Thirteenth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2013.
4.7.1*	Eleventh Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2016.
4.8.1*	Ninth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of December 8, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.375% senior notes due 2015.

4.9.1*	Seventh Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of April 19, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.625% senior notes due 2016.
4.10.1*	Sixth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of June 20, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.25% senior notes due 2018.
4.11.1*	Seventh Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of August 16, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.50% senior notes due 2017.
4.12.1*	Sixth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2020.
4.13.1*	Sixth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 2.75% contingent convertible senior notes due 2035.
4.14.1*	Third Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of June 30, 2006 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.625% senior notes due 2013.
4.15.1*	Second Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of December 6, 2006 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to the 6.25% senior notes due 2017.
4.16	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 2.50% Contingent Convertible Senior Notes due 2037. Incorporated herein by reference to Exhibit 4.1 to Chesapeake s current report on Form 8-K filed May 15, 2007.
4.16.1*	First Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of May 15, 2007 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 2.50% Contingent Convertible Senior Notes due 2037.
10.1.18	Chesapeake s Long Term Incentive Plan, as amended. Incorporated herein by reference to Exhibit 99.1 to Chesapeake s registration statement on Form S-8 (file no. 333-143,990) filed June 22, 2007.
10.5 *	Named Executive Officer Compensation.
12*	Computation of Ratios of Earnings to Fixed Charges and to Combined Fixed Charges and Preferred Stock Dividends.
31.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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* Filed herewith.
Management contract or compensatory plan or arrangement

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SIGNATURES

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

CHESAPEAKE ENERGY CORPORATION

(Registrant)

By: /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon
Chairman of the Board and
Chief Executive Officer

By: /s/ MARCUS C. ROWLAND
Marcus C. Rowland
Executive Vice President and
Chief Financial Officer

Date: August 8, 2007

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4.2.1*	Tenth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.
4.3.1*	Fourteenth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.75% senior notes due 2015.
4.6.1*	Thirteenth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2013.
4.7.1*	Eleventh Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2016.
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4.9.1*	Seventh Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of April 19, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.625% senior notes due 2016.
4.10.1*	Sixth Supplemental Indenture dated as of August 7, 2007 to Indenture dated as of June 20, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.25% senior notes due 2018.
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