CHESAPEAKE ENERGY CORP
Form 10-Q
May 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 March 31, 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	**(I.R.S. Employer**
incorporation or organization)	**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 May 4, 2007, there were 460,736,173 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)

	March 31, 2007	December 31, 2006
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4	$ 3
Accounts receivable	890	845
Deferred income taxes	110	
Short-term derivative instruments	130	225
Inventory and other	89	81
Total Current Assets	1,223	1,154
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full-cost accounting:		
Evaluated oil and natural gas properties	23,598	21,949
Unevaluated properties	3,889	3,797
Less: accumulated depreciation, depletion and amortization of oil and natural gas properties	(5,682)	(5,292)
Total oil and natural gas properties, at cost based on full-cost accounting	21,805	20,454
Other property and equipment:		
Natural gas gathering systems	648	552
Drilling rigs	315	301
Buildings and land	459	429
Natural gas compressors	150	127
Other	253	241
Less: accumulated depreciation and amortization of other property and equipment	(232)	(200)
Total Property and Equipment	23,398	21,904
OTHER ASSETS:		
Investments	704	699
Long-term derivative instruments	82	339
Other assets	325	321
Total Other Assets	1,111	1,359
TOTAL ASSETS	$ 25,732	$ 24,417

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	March 31, 2007	December 31, 2006
	($ in millions)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 895	$ 860
Accrued liabilities	463	419
Short-term derivative instruments	390	112
Revenues and royalties due others	323	318
Accrued interest	109	142
Deferred income taxes		39
Total Current Liabilities	2,180	1,890
LONG-TERM LIABILITIES:		
Long-term debt, net	8,371	7,376
Deferred income tax liability	3,373	3,317
Asset retirement obligation	201	193
Long-term derivative instruments	273	160
Revenues and royalties due others	35	30
Other liabilities	222	200
Total Long-Term Liabilities	12,475	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 March 31, 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 March 31, 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 March 31, 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 March 31, 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 March 31, 2007 and December 31, 2006, respectively, entitled in liquidation to $575 million	575	575
Common Stock, $.01 par value, 750,000,000 shares authorized, 461,385,659 and 458,600,789 shares issued at March 31, 2007 and December 31, 2006, respectively	5	5
Paid-in capital	5,895	5,873
Retained earnings	3,114	2,913
Accumulated other comprehensive income (loss), net of tax of ($73) million and ($319) million, respectively	123	528
Less: treasury stock, at cost; 906,557 and 1,167,007 common shares as of March 31, 2007 and December 31, 2006, respectively	(18)	(26)
Total Stockholders Equity	11,077	11,251

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 25,732	$ 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 March 31, 2007	2006
	($ in millions except per share data)	
REVENUES:		
Oil and natural gas sales	$ 1,125	$ 1,511
Oil and natural gas marketing sales	422	404
Service operations revenue	33	29
Total Revenues	1,580	1,944
OPERATING COSTS:		
Production expenses	142	119
Production taxes	42	55
General and administrative expenses	52	29
Oil and natural gas marketing expenses	407	391
Service operations expense	22	14
Oil and natural gas depreciation, depletion and amortization	393	305
Depreciation and amortization of other assets	36	24
Employee retirement expense		55
Total Operating Costs	1,094	992
INCOME FROM OPERATIONS	486	952
OTHER INCOME (EXPENSE):		
Interest and other income	9	10
Interest expense	(79)	(73)
Gain on sale of investment		117
Total Other Income (Expense)	(70)	54
INCOME BEFORE INCOME TAXES	416	1,006
INCOME TAX EXPENSE:		
Current		
Deferred	158	382
Total Income Tax Expense	158	382
NET INCOME	258	624
PREFERRED STOCK DIVIDENDS	(26)	(19)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK		(1)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 232	$ 604
EARNINGS PER COMMON SHARE:		

Basic	$	0.51	$	1.64
Assuming dilution	$	0.50	$	1.44
CASH DIVIDEND DECLARED PER COMMON SHARE	$	0.06	$	0.05
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic		451		369
Assuming dilution		516		431

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)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 258	$ 624
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	425	326
Deferred income taxes	153	382
Unrealized (gains) losses on derivatives	311	(197)
Amortization of loan costs and bond discount	6	5
Realized (gains) losses on financing derivatives	(42)	(27)
Stock-based compensation	14	59
Gain on sale of investment in Pioneer Drilling Company		(117)
Income from equity investments	(6)	(5)
Other	5	(4)
Change in assets and liabilities	(147)	(79)
Cash provided by operating activities	977	967
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisitions of oil and natural gas companies, proved and unproved properties, net of cash acquired	(419)	(958)
Exploration and development of oil and natural gas properties	(1,251)	(799)
Additions to other fixed assets	(177)	(95)
Additions to drilling rig equipment	(35)	(193)
Additions to investments	(17)	(29)
Acquisition of trucking company, net of cash acquired		(45)
Proceeds from sale of investment in Pioneer Drilling Company		159
Proceeds from sale of drilling rigs and equipment	30	
Deposits for acquisitions	(7)	
Sale of non-oil and natural gas assets	7	
Cash used in investing activities	(1,869)	(1,960)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	1,833	2,202
Payments on long-term borrowings	(858)	(1,830)
Proceeds from issuance of senior notes, net of offering costs		487
Cash paid for common stock dividends	(27)	(18)
Cash paid for preferred stock dividends	(26)	(19)
Derivative settlements	(22)	(30)
Net increase (decrease) in outstanding payments in excess of cash balance	(8)	72
Cash received from exercise of stock options	3	39
Excess tax benefit from stock-based compensation	4	77
Other financing costs	(6)	(9)
Cash provided by financing activities	893	971

Net increase (decrease) in cash and cash equivalents		1		(22)
Cash and cash equivalents, beginning of period		3		60
Cash and cash equivalents, end of period	$	4	$	38

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)

	Three Months Ended March 31, 2007	2006
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 104	$ 113
Income taxes, net of refunds received	$ 5	$
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:		

As of March 31, 2007 and 2006, dividends payable on our common and preferred stock were $53 million and $38 million, respectively.

For the three months ended March 31, 2007 and 2006, oil and natural gas properties were adjusted by $7 million and $81 million, respectively, for net income tax liabilities related to acquisitions.

For the three months ended March 31, 2007 and 2006, accrued exploration and development costs of $22 million and $14 million, respectively, were recorded as additions to oil and natural gas properties.

We recorded non-cash asset additions to net oil and natural gas properties of $5 million and $7 million for the three months ended March 31, 2007 and 2006, respectively, for asset retirement obligations.

For the three months ended March 31, 2007, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock and for the three months ended March 31, 2006, holders of the 4.125% preferred stock exchanged 2,750 shares for 172,594 shares of common stock in privately negotiated exchanges.

For the three months ended March 31, 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 three months ended March 31, 2006, holders of our 6.0% cumulative convertible preferred stock converted 99,310 shares into 482,694 shares of common stock.

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)

	Three Months Ended March 31,	
	2007	2006
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 1,958	$ 1,577
Exchange of common stock for 3 and 2,750 shares of 4.125% preferred stock		(3)
Exchange of common stock for 0 and 183,273 shares of 5.00% preferred stock (Series 2003)		(18)
Exchange of common stock for 0 and 99,310 shares of 6.00% preferred stock		(5)
Balance, end of period	1,958	1,551
COMMON STOCK:		
Balance, beginning of period	5	4
Exchange of 180 and 1,795,511 shares of common stock for preferred stock		
Balance, end of period	5	4
PAID-IN CAPITAL:		
Balance, beginning of period	5,873	3,803
Exchange of 180 and 1,795,511 shares of common stock for preferred stock		26
Equity-based compensation	15	59
Adoption of SFAS 123(R)		(89)
Exercise of stock options	3	40
Tax benefit from exercise of stock options and restricted stock	4	77
Balance, end of period	5,895	3,916
RETAINED EARNINGS:		
Balance, beginning of period	2,913	1,101
Net income	258	624
Dividends on common stock	(27)	(19)
Dividends on preferred stock	(26)	(19)
Adoption of FIN 48	(4)	
Balance, end of period	3,114	1,687
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	528	(195)
Hedging activity	(407)	477
Marketable securities activity	2	(51)
Balance, end of period	123	231
TREASURY STOCK - COMMON:		
Balance, beginning of period	(26)	(26)
Release of 260,447 and 701 shares for company benefit plans	8	

Balance, end of period	(18)	(26)
TOTAL STOCKHOLDERS EQUITY	$ 11,077	$ 7,363

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 March 31, 2007	Three Months Ended March 31, 2006
	($ in millions)	
Net income	$ 258	$ 624
Other comprehensive income, net of income tax:		
Change in fair value of derivative instruments, net of income taxes of ($132) million and $409 million	(213)	667
Reclassification of (gain) loss on settled contracts, net of income taxes of ($138) million and ($79) million	(228)	(129)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $20 million and ($38) million	34	(62)
Unrealized gain (loss) on marketable securities, net of income taxes of $1 million and $14 million	2	22
Reclassification of gain on sales of investments, net of income taxes of $0 and ($45) million		(73)
Comprehensive income (loss)	$ (147)	$ 1,049

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 months ended March 31, 2007 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three months ended March 31, 2007 (the Current Quarter) and the three months ended March 31, 2006 (the Prior Quarter).

Stock-Based Compensation

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 or oil and natural gas marketing expenses. We recorded the following stock-based compensation during the Current Quarter and the Prior Quarter ($ in millions):

	Three Months Ended March 31,	
	2007	2006
Production expenses	$ 3	$ 1
General and administrative expenses	10	6
Oil and natural gas marketing expense	1	
Employee retirement expense		52
Oil and natural gas properties	9	5
Total	$ 23	$ 64

Restricted Stock. Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. 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 four 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 March 31, 2007, and changes during the Current Quarter, 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	2,594,045	$ 27.92
Vested	(909,436)	$ 22.22
Forfeited	(103,089)	$ 27.26

Unvested shares as of March 31, 2007	8,656,281	$	26.83

The aggregate intrinsic value of restricted stock vested during the Current Quarter was approximately $25 million.

As of March 31, 2007, there was $209 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.91 years.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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 Quarter and the Prior Quarter, 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.

Stock Options. We granted stock options in previous years under several stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable over a four-year period.

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

	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	(538,038)	$ 6.30		$ 13
Forfeited	(6,736)	$ 10.65		
Outstanding at March 31, 2007	6,060,929	$ 7.52	5.14	$ 142
Exercisable at March 31, 2007	5,419,265	$ 7.20	5.00	$ 128

(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 March 31, 2007, there was $1 million of total unrecognized compensation cost related to unvested stock options. The cost is expected to be recognized over a weighted average period of approximately 100 days.

During the Current Quarter and the Prior Quarter, we recognized excess tax benefits related to stock options of $3 million and $74 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 alternative minimum tax liabilities associated with uncertain tax positions. 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 March 31, 2007, we had a liability of $9 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.

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 early 2008. As of March 31, 2007, the IRS has proposed a limited number of adjustments. We are currently evaluating the

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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 March 31, 2007, our oil and natural gas derivative instruments were comprised of 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.

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.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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) included in oil and natural gas sales were $433 million and $248 million in the Current Quarter and the Prior Quarter, respectively. 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. Unrealized gains (losses) included in oil and natural gas sales were ($309) million and $198 million, in the Current Quarter and the Prior Quarter, respectively.

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). We recorded an unrealized gain (loss) on ineffectiveness of ($54) million and $99 million in the Current Quarter and the Prior Quarter, respectively.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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

	March 31, 2007	December 31, 2006
	($ in millions)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ (323)	$ 1
Natural gas basis protection swaps	186	187
Fixed-price natural gas cap-swaps	(22)	122
Fixed-price natural gas counter-swaps		(5)
Natural gas call options[(a)]	(172)	(5)
Fixed-price natural gas collars	(26)	(7)
Fixed-price natural gas three-way collars	(45)	
Fixed-price oil swaps	(1)	28
Fixed-price oil cap-swaps	13	24
Oil call options[(b)]	(8)	
Estimated fair value	$ (398)	$ 345

(a) After adjusting for $119 million and $15 million of unrealized premiums, the cumulative unrealized gain (loss) related to these call options as of March 31, 2007 and December 31, 2006 was ($53) million and $10 million, respectively.

(b) After adjusting for $8 million of unrealized premiums, the cumulative unrealized loss related to these call options as of March 31, 2007 was less than $1 million.

In 2006 and 2007, Chesapeake lifted a portion of its 2007, 2008 and 2009 hedges and as a result has approximately $500 million of deferred hedging gains as of March 31, 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 March 31, 2007, we expect to transfer approximately $94 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 March 31, 2007 are expected to mature by December 31, 2009.

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 March 31, 2007	$ 10	$ (263)	$ (77)
Fair value of outstanding transactions, as of May 4, 2007	$	$ (42)	$ 49

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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. The aggregate fair value of the remaining CNR derivatives as of March 31, 2007 was a liability of $311 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 ($2) million and $1 million in the Current Quarter and the Prior Quarter, 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 ($1) million, in both the Current Quarter and the Prior Quarter.

As of March 31, 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	$ (3)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	(5)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	(5)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(6)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	(2)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	(5)
December 2006 July 2013	$ 250,000,000	7.625%	6 month LIBOR plus 266.5 basis points	(2)
January 2007 July 2013	$ 250,000,000	7.625%	6 month LIBOR plus 251 basis points	1
February 2007 August 2017	$ 250,000,000	6.500%	6 month LIBOR plus 124.5 basis points	1
				$ (26)

In the Current Quarter, we sold call options to a counterparty with respect to two of the interest rate swaps above and received $4 million in premiums. If exercised, the call option on the 7.625% interest rate swap gives the counterparty the right to terminate the interest rate swap on

July 12, 2007 for a payment to Chesapeake of $2 million. The call option on the 6.50% interest rate swap gives the counterparty the right to terminate the interest rate swap on August 15, 2007 for a payment of $2 million to Chesapeake.

In the Current Quarter, we closed one interest rate swap for a gain totaling $1 million. This interest rate swap was designated as a fair value hedge, and the settlement amount received will be amortized as a reduction to realized interest expense over the remaining terms 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 ($802 million at March 31, 2007) using an exchange rate of $1.3374 to 1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as a liability of $20 million at March 31, 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 March 31, 2007 and December 31, 2006 were $7.227 billion and $7.215 billion, respectively, compared to approximate fair values of $7.444 billion and $7.336 billion, respectively. The carrying amount for our convertible preferred stock as of March 31, 2007 and December 31, 2006 was $1.958 billion, compared to approximate fair values of $1.986 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

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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.

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 fraud with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions.

Chesapeake and NiSource maintain CNR acted in good faith and paid royalties in accordance with lease terms and West Virginia law, and we intend to appeal any adverse judgment in the case. On March 5, 2007, the Circuit Court heard a joint motion for post-trial review of punitive damages filed by Chesapeake and NiSource. The Circuit Court has indicated it will rule on the motion in May 2007. 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 secretarial 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 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 March 31, 2007.

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Rig Leases

In a series of transactions in 2006 and 2007, our wholly owned subsidiary, Nomac Drilling Corporation, has sold 27 of its drilling rigs and related equipment for $274 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 $36 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 $28 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 March 31, 2007, the minimum aggregate future rig lease payments were approximately $290 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 March 31, 2007, the aggregate amount of such required demand payments was approximately $379 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 43 rigs with terms of one to three years. As of March 31, 2007, the minimum aggregate drilling rig commitment was approximately $364 million.

As of March 31, 2007, Chesapeake s service operations companies have contracted to acquire 12 rigs to be constructed during 2007. The total remaining cost of the rigs is estimated to be approximately $86 million.

Other Commitments

As of March 31, 2007, Chesapeake has contracted to acquire compressors during 2007, 2008 and 2009 for a total commitment of $165 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 March 31, 2007, there was $29 million outstanding 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 March 31, 2007, there was $18 million outstanding under this agreement. Additionally, we have agreed to guarantee various commitments for Ventura, up to $75 million, to support their operating activities.

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.

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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 32,596 shares) and the preferred stock adjustment to net income does not include dividends and loss on conversion related to these preferred shares which amount to less than $1 million 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 235,584 shares), and the preferred stock adjustment to net income does not include $1 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 months ended March 31, 2007 and 2006 are as follows:

	Income (Numerator)	**Shares (Denominator)**	**Per Share Amount**
	(in millions, except per share data)		
For the Three Months Ended March 31, 2007:			
Basic EPS:			
Income available to common shareholders	$ 232	451	$ 0.51
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		19	
Employee stock options		3	
Restricted stock		2	
Preferred stock dividends	26		
Diluted EPS Income available to common shareholders and assumed conversions	$ 258	516	$ 0.50
For the Three Months Ended March 31, 2006:			
Basic EPS:			
Income available to common shareholders	$ 604	369	$ 1.64
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 4.125% convertible preferred stock		5	
Common shares assumed issued for 4.50% convertible preferred stock		8	

Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		5	
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		9	
Restricted stock		2	
Preferred stock dividends	19		
Diluted EPS Income available to common shareholders and assumed conversions	$ 623	431	$ 1.44

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5. Stockholders Equity

The following is a summary of the changes in our common shares outstanding for the three months ended March 31, 2007 and 2006:

	2007	2006
	(in thousands)	
Shares outstanding at January 1	458,601	375,511
Stock option exercises	532	8,354
Restricted stock issuances	2,253	1,693
Preferred stock conversions/exchanges		1,795
Shares outstanding at March 31	461,386	387,353

The following is a summary of the changes in our preferred shares outstanding for the three months ended March 31, 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 March 31, 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	
Conversion/exchange of preferred for common stock	(99)	(183)	(3)				
Shares outstanding at March 31, 2006		843	86	4,600	3,450	5,750	

In connection with the exchanges and conversions noted above, we recorded a loss of $1 million in the Prior Quarter. In general, the loss is 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.

During the Current Quarter, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock and in the Prior Quarter holders of the 4.125% preferred stock exchanged 2,750 shares for 172,594 shares of our common stock.

During the Prior Quarter, holders of our 5.0% (Series 2003) cumulative convertible preferred stock exchanged 183,273 shares for 1,140,223 shares of our common stock.

During the Prior Quarter, the remaining 99,310 shares of our 6.0% preferred stock were converted into or exchanged for 482,694 shares of common stock.

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6. Senior Notes and Revolving Bank Credit Facility

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

	March 31, 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)]	802	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
Revolving bank credit facility	1,153	178
Discount on senior notes	(99)	(101)
Discount for interest rate derivatives[(c)]	(9)	(17)
Total notes payable and long-term debt	$ 8,371	$ 7,376

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3374 to 1.00 and $1.3197 to 1.00 as of March 31, 2007 and December 31, 2006, respectively. See Note 2 for information on our related cross currency swap.

(b) 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, or upon a fundamental change, at 100% of the principal amount of these notes. 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 nine-month period ending May 14, 2016, under certain conditions. We may redeem the convertible senior notes on or after November 15, 2015 at a redemption price of 100% of the principal amount of such notes.

(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, 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 March 31, 2007, we had $1.153 billion in outstanding borrowings under our facility and utilized $3 million of the facility for various letters of credit. Borrowings under our facility are collateralized by certain producing oil and natural gas

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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) 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 0.43 to 1 and our indebtedness to EBITDA ratio was 1.86 to 1 at March 31, 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 Limited Partnership 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.

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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 $705 million and $691 million for the Current Quarter and the Prior Quarter, 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 March 31, 2007:					
Revenues	$ 1,125	$ 1,127	$ 108	$ (780)	$ 1,580
Intersegment revenues		(705)	(75)	780	
Total revenues	$ 1,125	$ 422	$ 33	$	$ 1,580
Income before income taxes	$ 405	$ 8	$ 30	$ (27)	$ 416
For the Three Months Ended March 31, 2006:					
Revenues	$ 1,511	$ 1,095	$ 49	$ (711)	$ 1,944
Intersegment revenues		(691)	(20)	711	
Total revenues	$ 1,511	$ 404	$ 29	$	$ 1,944
Income before income taxes	$ 989	$ 12	$ 11	$ (6)	$ 1,006
As of March 31, 2007:					
Total assets	$ 24,478	$ 976	$ 791	$ (513)	$ 25,732
As of December 31, 2006:					
Total assets	$ 23,333	$ 864	$ 786	$ (566)	$ 24,417

8. Acquisitions

Oil and Natural Gas Properties

Through multiple acquisitions completed in the Current Quarter, we invested $215 million in proved properties, including approximately $7 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. Additionally, we invested $258 million in unproved property acquisitions.

9. Recently Issued 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, SFAS 157 will have on our financial position, results of operations or cash flows.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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.

10. Subsequent Events

On April 30, 2007, we announced that we entered into a letter of intent with Gastar Exploration Ltd. to acquire a portion of Gastar s East Texas undeveloped leasehold for total consideration of approximately $92 million, including the purchase of 10 million newly issued Gastar common shares at a price of $2.00 per share. Following the transaction, Chesapeake would own a total of 42.2 million Gastar common shares, or approximately 20.5% of Gastar s basic shares outstanding. This transaction is subject to another party s right of first refusal.

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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 months ended March 31, 2007 (the Current Quarter) and the three months ended March 31, 2006 (the Prior Quarter):

	Three Months Ended March 31,	
	2007	**2006**
Net Production:		
Oil (mbbls)	2,143	2,116
Natural gas (mmcf)	140,792	124,056
Natural gas equivalent (mmcfe)	153,650	136,752
Oil and Natural Gas Sales ($ in millions):		
Oil sales	$ 113	$ 125
Oil derivatives realized gains (losses)	18	(4)
Oil derivatives unrealized gains (losses)	(12)	(1)
Total oil sales	119	120
Natural gas sales	888	940
Natural gas derivatives realized gains (losses)	415	252
Natural gas derivatives unrealized gains (losses)	(297)	199
Total natural gas sales	1,006	1,391
Total oil and natural gas sales	$ 1,125	$ 1,511
Average Sales Price (excluding all gains (losses) on derivatives):		
Oil ($ per bbl)	$ 52.80	$ 58.92
Natural gas ($ per mcf)	$ 6.31	$ 7.58
Natural gas equivalent ($ per mcfe)	$ 6.52	$ 7.79
Average Sales Price (excluding unrealized gains (losses) on derivatives):		
Oil ($ per bbl)	$ 61.13	$ 57.12
Natural gas ($ per mcf)	$ 9.26	$ 9.61
Natural gas equivalent ($ per mcfe)	$ 9.33	$ 9.60
Other Operating Income[(a)] ($ in millions):		
Oil and natural gas marketing	$ 15	$ 13
Service operations	$ 11	$ 15
Other Operating Income ($ per mcfe):		
Oil and natural gas marketing	$ 0.10	$ 0.10
Service operations	$ 0.08	$ 0.11
Expenses ($ per mcfe):		
Production expenses	$ 0.93	$ 0.87
Production taxes	$ 0.27	$ 0.40
General and administrative expenses	$ 0.34	$ 0.21
Oil and natural gas depreciation, depletion and amortization	$ 2.56	$ 2.23
Depreciation and amortization of other assets	$ 0.23	$ 0.17
Interest expense[(b)]	$ 0.50	$ 0.52
Interest Expense ($ in millions):		

Interest expense	$ 76	$ 73
Interest rate derivatives realized (gains) losses	2	(1)
Interest rate derivatives unrealized (gains) losses	1	1
Total interest expense	$ 79	$ 73
Net Wells Drilled	461	255
Net Producing Wells as of the End of the Period	19,623	17,669

(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.

Chesapeake is the third largest independent and the sixth largest overall producer of natural gas in the United States. We own interests in approximately 35,500 producing oil and natural gas wells that are currently producing approximately 1.8 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves 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 March 31, 2007, 47% 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 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 shale play in the U.S., 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 Conasauga, Floyd and Chattanooga Shales in Alabama.

Oil and natural gas production for the Current Quarter was 153.7 bcfe, an increase of 16.9 bcfe, or 12% over the 136.8 bcfe produced in the Prior Quarter. We have increased our production for 23 consecutive quarters. During these 23 quarters, Chesapeake s U.S. production has increased 326% for an average compound quarterly growth rate of 6.5% and an average compound annual growth rate of 29%.

The increased oil and natural gas production was partially offset by a decrease in the prices we received 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 $9.33 per mcfe in the Current Quarter compared to $9.60 per mcfe in the Prior Quarter. The decrease in prices resulted in a decrease in revenue of $41 million, and increased production resulted in an increase in revenue of $162 million, for a total increase in revenue of $121 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 129 operated rigs and 94 non-operated rigs. Through this drilling activity, we drilled 476 (404 net) operated wells and participated in another 394 (57 net) wells operated by other companies. Our drilling success rate was 99% for company-operated wells and 98% for non-operated wells. During the Current Quarter, Chesapeake invested $906 million in operated wells, $160 million in non-operated wells and $198 million in acquiring 3-D seismic data and leasehold (excluding leasehold acquired through acquisitions). Our acquisition expenditures totaled $465 million during the Current Quarter, including amounts paid for unproved leasehold and excluding $7 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 9.431 tcfe, an increase of 475 bcfe, or 5.3%. During the Current Quarter, we replaced 154 bcfe of production with an estimated 629 bcfe of new proved reserves, for a reserve replacement rate of 410%. Reserve replacement through the drillbit was 535 bcfe, or 349% of production (including 205 bcfe of positive performance revisions and 135 bcfe of positive revisions resulting from oil and natural gas price increases between December 31, 2006 and March 31, 2007) and 85% of the total increase. Reserve replacement through the acquisition of proved reserves was 94 bcfe, or 61% 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 approximately 1,100 employees. Today, the company has over 5,000 employees, of which approximately 60% work in the company s E&P operations and 40% work in the company s oilfield service operations.

Since 2000, Chesapeake has invested $7.1 billion in new leasehold and 3-D seismic acquisitions and now owns one of the largest inventories of onshore leasehold (11.2 million net acres) and 3-D seismic (16.7 million acres) in the U.S. On this leasehold, the company has an estimated 26,500 net drilling locations, representing an approximate 10-year inventory of drilling projects.

As of March 31, 2007, the company s debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 43% compared to 40% as of December 31, 2006. The average maturity of our long-term debt is over nine years and our average interest rate is approximately 6.5%.

We intend to continue to focus on improving the strength of our balance sheet. We believe our business strategy and operational performance will lead to an investment grade credit rating for our unsecured debt at some point in the future.

Liquidity and Capital Resources

Sources and Uses of Funds

Our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for certain acquisitions) is cash flow from operations. Based on our current assumptions of production, prices and expenses, we expect our drilling, land and seismic capital expenditures in 2007 to exceed our cash flow from operations. Any additional funds required will be initially provided through additional borrowings under our bank credit facility. Our budget for drilling, land and seismic activities during 2007 is currently between $5.0 billion and $5.2 billion. 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 10% and increase our total production by 14% to 18% (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). However, 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.

Cash provided by operating activities was $977 million in the Current Quarter compared to $967 million in the Prior Quarter. The $10 million increase was primarily due to higher oil and natural gas production. We expect that 2007 production volumes will be higher than in 2006 and that cash provided by operating activities in 2007 will exceed 2006 levels. While a decline in 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 77% of our expected remaining oil production in 2007 at an average NYMEX price of $71.47 per barrel of oil and natural gas swaps in place covering 54% of our expected remaining natural gas production in 2007 at an average NYMEX price of $8.49 per mcf, along with natural gas collars covering 13% of our anticipated remaining natural gas production for 2007 with an average NYMEX floor of $6.88 per mcf and an average NYMEX ceiling of $8.41 per mcf. Additionally, we have written call options covering 13% of our 2007 remaining natural gas production at a weighted average price of $9.48. 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, however, we may increase or decrease our current hedging positions.

Based on fluctuations in natural gas and oil prices, 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 March 31, 2007 and May 4, 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 collateral with our counterparties through letters of credit issued under our bank credit facility. Future collateral requirements are uncertain and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

A significant source of liquidity is our $2.5 billion syndicated revolving bank credit facility which matures in February 2011. At May 4, 2007, there was $886 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 $1.833 billion and repaid $858 million in the Current Quarter, and we borrowed $2.202 billion and repaid $1.830 billion in the Prior Quarter under the credit facility.

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We expect our operating costs, debt service, capital expenditures, short-term contractual obligations and dividend payments in 2007 will, at times, exceed our available cash, cash provided by operating activities and funds available under our revolving bank credit facility. We are considering various alternatives to meet the shortfall.

The public and institutional markets have been our principal source of long-term financing for acquisitions, although there were no issuances of debt or equity securities in the Current Quarter and no issuances of equity securities in the Prior Quarter. We issued $500 million principal amount of 6.5% Senior Notes due 2017 and received net proceeds of $487 million in the Prior Quarter. 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.

We paid dividends on our common stock of $27 million and $18 million in the Current Quarter and the Prior Quarter, respectively. The board of directors increased the quarterly dividend on common stock from $0.05 to $0.06 per share beginning with the dividend paid in July 2006. We paid dividends on our preferred stock of $26 million and $19 million in the Current Quarter and the Prior Quarter, respectively. We received $3 million and $39 million from the exercise of employee and director stock options in the Current Quarter and the Prior Quarter, respectively. The Prior Quarter amount included $37 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 Quarter and Prior Quarter, we paid $22 million and $30 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 Quarter and the Prior Quarter, we reported a tax benefit from stock-based compensation of $4 million and $77 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists decreased $8 million in the Current Quarter and increased $72 million in the Prior Quarter. 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 ($627 million at March 31, 2007) and exploration and production companies which own interests in properties we operate ($147 million at March 31, 2007). 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.

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Investing Transactions

Cash used in investing activities decreased to $1.869 billion during the Current Quarter, compared to $1.960 billion during the Prior Quarter. The following table shows our cash used in (provided by) investing activities during these periods ($ in millions):

	Three Months Ended March 31,	
	2007	2006
Oil and Natural Gas Investing Activities:		
Acquisitions of oil and natural gas companies and proved properties, net of cash acquired	$ 162	$ 412
Acquisition of unproved properties	258	546
Exploration and development of oil and natural gas properties	1,053	597
Leasehold acquisitions	148	173
Geological and geophysical costs	50	27
Other oil and natural gas activities	(1)	2
Total oil and natural gas investing activities	1,670	1,757
Other Investing Activities:		
Additions to buildings and other fixed assets	177	95
Additions to drilling rig equipment	35	193
Proceeds from sale of drilling rigs and equipment	(30)	
Additions to investments	17	29
Proceeds from sale of investment in Pioneer Drilling Company `		(159)
Acquisition of trucking company, net of cash acquired		45
Deposits for acquisitions	(7)	
Sale of non-oil and natural gas assets	7	
Total other investing activities	199	203
Total cash used in investing activities	$ 1,869	$ 1,960

Contractual Obligations

We have a $2.5 billion syndicated revolving bank credit facility which matures in February 2011. As of March 31, 2007, we had $1.153 billion in outstanding borrowings under this facility and had utilized $3 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 0.43 to 1 and our indebtedness to EBITDA ratio was 1.86 to 1 at March 31, 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.

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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 March 31, 2007	$ 10	$ (263)	$ (77)
Fair value of outstanding transactions, as of May 4, 2007	$	$ (42)	$ 49

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake Exploration Limited Partnership 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 March 31, 2007, senior notes represented approximately $7.218 billion of our long-term debt and consisted of the following ($ 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]	802
6.25% Senior Notes due 2018	600
6.875% Senior Notes due 2020	500
2.75% Contingent Convertible Senior Notes due 2035	690
Discount on senior notes	(99)
Discount for interest rate derivatives	(9)
	$ 7,218

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3374 to 1.00 as of March 31, 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 these notes.

As of March 31, 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 March 31, 2007, we estimate that secured commercial bank indebtedness of approximately $3.473 billion could have been incurred under the most restrictive indenture covenant.

Results of Operations Three Months Ended March 31, 2007 vs. March 31, 2006

General. For the Current Quarter, Chesapeake had net income of $258 million, or $0.50 per diluted common share, on total revenues of $1.580 billion. This compares to net income of $624 million, or $1.44 per diluted common share, on total revenues of $1.944 billion during the Prior Quarter.

Oil and Natural Gas Sales. During the Current Quarter, oil and natural gas sales were $1.125 billion compared to $1.511 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 153.7 bcfe at a weighted average price of $9.33 per mcfe, compared to 136.8 bcfe produced in the Prior Quarter at a weighted average price of $9.60 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of ($309) million and $198 million in the Current Quarter and Prior Quarter, respectively). In the Current Quarter, the decrease in prices resulted in a decrease in revenue of $41 million and increased production resulted in a $162 million increase, for a total increase in revenues of $121 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 the Current Quarter.

For the Current Quarter, we realized an average price per barrel of oil of $61.13, compared to $57.12 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 $9.26 and $9.61 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 $433 million, or $2.82 per mcfe, in the Current Quarter and $248 million, or $1.82 per mcfe, in the Prior Quarter.

The change in oil and natural gas prices has a significant impact on our oil and natural gas revenues and cash flows. 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 $14 million 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 March 31,			
	2007		2006	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	81,705	53%	73,924	54%
Fort Worth Barnett Shale	16,155	11	8,565	6
Appalachian Basin	11,080	7	10,293	8
Permian and Delaware Basins	12,706	8	12,094	9
Ark-La-Tex	12,860	8	11,590	8
South Texas and Texas Gulf Coast	19,144	13	20,286	15
Total production	153,650	100%	136,752	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 $422 million in oil and natural gas marketing sales in the Current Quarter, with corresponding oil and natural gas marketing expenses of $407 million, for a net margin before depreciation of $15 million. This compares to sales of $404 million, expenses of $391 million and a net margin of $13 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.

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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 $33 million in service operations revenue in the Current Quarter with corresponding service operations expense of $22 million, for a net margin before depreciation of $11 million. This compares to revenue of $29 million, expenses of $14 million and a net margin before depreciation of $15 million.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $142 million in the Current Quarter compared to $119 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.93 per mcfe in the Current Quarter compared to $0.87 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 $42 million in the Current Quarter compared to $55 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.27 per mcfe in the Current Quarter compared to $0.40 per mcfe in the Prior Quarter. The $13 million decrease in production taxes in the Current Quarter is due primarily to a price decrease of approximately $1.27 per mcfe (excluding gains or losses on derivatives) and an increase in qualified production tax exemptions in Texas which more than offset the 16.9 bcfe of increased production.

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 $0.41 to $0.46 per mcfe based on NYMEX prices of $56.73 per barrel of oil and natural gas wellhead prices ranging from $7.40 to $8.40 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 $52 million in the Current Quarter and $29 million in the Prior Quarter. General and administrative expenses were $0.34 and $0.21 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 $10 million and $6 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. We have awarded shares of restricted stock to employees since January 2004 and to non-employee directors since July 2005. Previously, stock-based compensation awards were in the form of stock options. Employee stock-based compensation awards vest over a period of four 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, as well as the effects of our adoption of SFAS 123(R).

Chesapeake follows the full-cost method of accounting under which all costs associated with 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 $51 million and $35 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.

Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was $393 million and $305 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 $2.56 and $2.23 in the Current Quarter and in the Prior Quarter, respectively. The $0.33 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.

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Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $36 million in the Current Quarter, compared to $24 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.

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 Quarter.

Interest and Other Income. Interest and other income was $9 million in the Current Quarter compared to $10 million in the Prior Quarter. The Current Quarter income consisted of $2 million of interest income, $6 million related to earnings of equity investees and $1 million of miscellaneous income. The Prior Quarter income consisted of $2 million of interest income, $5 million related to earnings of equity investees and a $3 million gain on sale of assets.

Interest Expense. Interest expense increased to $79 million in the Current Quarter compared to $73 million in the Prior Quarter as follows:

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 135	$ 102
Capitalized interest	(64)	(31)
Realized (gain) loss on interest rate derivatives	2	(1)
Unrealized (gain) loss on interest rate derivatives	1	1
Amortization of loan discount and other	5	2
Total interest expense	$ 79	$ 73
Average long-term borrowings	$ 7,324	$ 5,775

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.50 per mcfe in the Current Quarter compared to $0.52 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 Investment. In the Prior Quarter, 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 $158 million in the Current Quarter, compared to income tax expense of $382 million in the Prior Quarter. Our effective income tax rate was 38% in the Current Quarter and the Prior Quarter. Most of 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 $1 million in the Prior Quarter. The loss on the exchange 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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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 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, SFAS 157 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.

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, our level of indebtedness,

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- the strength and financial resources of our competitors,
- the availability of capital on an economic basis to fund reserve replacement costs,
- our ability to replace reserves and sustain production,
- 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 March 31, 2007, our oil and natural gas derivative instruments were comprised of 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.

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 derivative transactions are reflected as adjustments to oil and natural gas sales on the condensed consolidated statements of operations. Realized gains (losses) included in oil and natural gas sales were $433 million and $248 million in the Current Quarter and the Prior Quarter, respectively. 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. Unrealized gains (losses) included in oil and natural gas sales were ($309) million and $198 million in the Current Quarter and the Prior Quarter, respectively.

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). We recorded an unrealized gain (loss) on ineffectiveness of ($54) million and $99 million in the Current Quarter and the Prior Quarter, respectively.

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As of March 31, 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 March 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 March 31, 2007 ($ in millions)
Natural Gas (mmbtu):								
Swaps:								
2Q 2007	17,890,000	$ 6.70	$	$	$	Yes	$	$ (19)
3Q 2007	18,820,000	6.99				Yes		(21)
4Q 2007	34,130,000	8.01				Yes		(34)
1Q 2008	64,382,500	10.01				Yes		14
2Q 2008	51,642,500	8.34				Yes		16
3Q 2008	52,210,000	8.40				Yes		11
4Q 2008	50,990,000	9.02				Yes		12
Basis Protection Swaps (Mid-Continent):								
2Q 2007	47,775,000				(0.47)	No		32
3Q 2007	48,300,000				(0.47)	No		13
4Q 2007	40,370,000				(0.37)	No		29
1Q 2008	33,215,000				(0.30)	No		30
2Q 2008	26,845,000				(0.25)	No		18
3Q 2008	27,140,000				(0.25)	No		16
4Q 2008	31,410,000				(0.28)	No		22
1Q 2009	26,100,000				(0.32)	No		16
2Q 2009	20,020,000				(0.28)	No		3
3Q 2009	20,240,000				(0.28)	No		3
4Q 2009	20,240,000				(0.28)	No		5
Basis Protection Swaps (Appalachian Basin):								
2Q 2007	9,100,000				0.35	No		
3Q 2007	9,200,000				0.35	No		
4Q 2007	9,200,000				0.35	No		
1Q 2008	9,100,000				0.35	No		(1)
2Q 2008	9,100,000				0.35	No		
3Q 2008	9,200,000				0.35	No		
4Q 2008	9,200,000				0.35	No		
1Q 2009	4,500,000				0.31	No		
2Q 2009	4,550,000				0.31	No		
3Q 2009	4,600,000				0.31	No		
4Q 2009	4,600,000				0.31	No		
Cap-Swaps:								
2Q 2007	49,470,000	8.32	5.87			No		28
3Q 2007	54,270,000	8.49	5.89			No		(1)
4Q 2007	48,490,000	9.33	5.92			No		(9)
1Q 2008	45,500,000	10.51	6.06			No		(4)
2Q 2008	47,320,000	9.24	6.17			No		1
3Q 2008	47,840,000	9.34	6.17			No		(7)
4Q 2008	40,520,000	9.93	6.14			No		(6)
1Q 2008	18,000,000	10.09	6.10			No		(7)
2Q 2008	15,470,000	8.52	6.12			No		(5)

3Q 2008	15,640,000	8.64	6.12		No		(6)
4Q 2008.	15,450,000	9.20	6.12		No		(6)
Counter Swaps:							
2Q 2007	(1,375,000)	(7.73)			No		
Call Options:							
2Q 2007	14,560,000			9.50	No	7	(1)
3Q 2007	21,430,000			9.30	No	11	(11)
4Q 2007	27,280,000			9.62	No	15	(28)
1Q 2008	28,210,000			10.24	No	19	(42)
2Q 2008	25,480,000			10.44	No	15	(12)
3Q 2008	25,760,000			10.44	No	16	(16)
4Q 2008	24,540,000			10.46	No	15	(25)
1Q 2009	15,300,000			11.44	No	6	(17)
2Q 2009	12,740,000			11.54	No	5	(4)
3Q 2009	12,880,000			11.54	No	5	(7)
4Q 2009	12,880,000			11.54	No	5	(9)

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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 March 31, 2007 ($ in millions)
Collars:								
2Q 2007	2,730,000	$	$ 7.00	$ 8.35	$	Yes	$	$
3Q 2007	2,760,000		7.00	8.35		Yes		(1)
4Q 2007	5,810,000		7.26	9.06		Yes		(5)
1Q 2008	7,590,000		7.32	9.17		Yes		(10)
2Q 2008	910,000		7.50	8.65		Yes		
3Q 2008	920,000		7.50	8.65		Yes		
4Q 2008	920,000		7.50	8.65		Yes		(1)
Three-Way Collars:								
2Q 2007	19,110,000		6.73 /5.07	8.18		No		(4)
3Q 2007	19,320,000		6.73 / 5.07	8.18		No		(11)
4Q 2007	13,830,000		7.08 / 5.28	8.80		No		(12)
1Q 2008	10,920,000		7.40 / 5.46	9.35		No		(15)
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		1
4Q 2009	4,600,000		7.50 / 6.00	10.72		No		(1)
Total Natural Gas							119	(91)
Oil (bbls):								
Swaps:								
2Q 2007	910,000	69.55				Yes		2
3Q 2007	920,000	69.24				Yes		
4Q 2007	920,000	68.85				Yes		(1)
1Q 2008	819,000	70.29				Yes		
2Q 2008	819,000	69.89				Yes		
3Q 2008	828,000	69.48				Yes		(1)
4Q 2008	736,000	68.55				Yes		(1)
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		
Cap-Swaps:								
2Q 2007	728,000	73.30	55.63			No		4
3Q 2007	736,000	74.58	55.63			No		3
4Q 2007	736,000	74.98	55.63			No		2
1Q 2008	728,000	75.71	53.44			No		1
2Q 2008	728,000	75.90	53.44			No		1
3Q 2008	736,000	76.02	53.44			No		1
4Q 2008	736,000	76.09	53.44			No		1
1Q 2009	360,000	76.23	52.50			No		
2Q 2009	364,000	76.53	52.50			No		
3Q 2009	368,000	76.72	52.50			No		
4Q 2009	368,000	76.83	52.50			No		
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	184,000			75.00		No	1	(1)

1Q 2009	180,000	75.00	No	1	(1)
2Q 2009	182,000	75.00	No	1	(1)
3Q 2009	184,000	75.00	No	1	(1)
4Q 2009	184,000	75.00	No	1	(1)
Total Oil				8	4
Total Natural Gas and Oil				$ 127	$ (87)

In 2006 and 2007, Chesapeake lifted a portion of its 2007, 2008 and 2009 hedges and as a result has approximately $500 million of deferred hedging gains as of March 31, 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.

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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 do 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.

The following details the assumed CNR derivatives remaining as of March 31, 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 March 31, 2007 ($ in millions)
Natural Gas (mmbtu):						
Swaps:						
2Q 2007	10,465,000	$ 4.82	$	$	Yes	$ (30)
3Q 2007	10,580,000	4.82			Yes	(34)
4Q 2007	10,580,000	4.82			Yes	(42)
1Q 2008	9,555,000	4.68			Yes	(47)
2Q 2008	9,555,000	4.68			Yes	(30)
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	(17)
2Q 2009	4,550,000	5.18			Yes	(10)
3Q 2009	4,600,000	5.18			Yes	(11)
4Q 2009	4,600,000	5.18			Yes	(13)
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						$ (311)

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 March 31, 2007.

Based upon the market prices at March 31, 2007, we expect to transfer approximately $94 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 March 31, 2007 are expected to mature by December 31, 2009.

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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	(161)
Fair value of contracts when entered into during the period	(114)
Contracts realized or otherwise settled during the period	(433)
Fair value of contracts when closed during the period	(35)
Fair value of contracts outstanding, as of March 31	$ (398)

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.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of March 31, 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 ($ in billions)	Thereafter	Total	Fair Value
Liabilities:								
Long-term debt-fixed-rate[(a)]	$	$	$	$	$	$ 7.327	$ 7.327	$ 7.444
Average interest rate						6.5%	6.5%	6.5%
Long-term debt-variable rate	$	$	$	$	$ 1.153	$	$ 1.153	$ 1.153
Average interest rate					6.7%		6.7%	6.7%

(a) This amount does not include the discount included in long-term debt of ($99) million and the discount for interest rate swaps of ($9) 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 ($2) million and $1 million in the Current Quarter and the Prior Quarter, 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 ($1) million and ($1) million, in the Current Quarter and the Prior Quarter, respectively.

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As of March 31, 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	$ (3)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	(5)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	(5)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(6)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	(2)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	(5)
December 2006 July 2013	$ 250,000,000	7.625%	6 month LIBOR plus 266.5 basis points	(2)
January 2007 July 2013	$ 250,000,000	7.625%	6 month LIBOR plus 251 basis points	1
February 2007 August 2017	$ 250,000,000	6.500%	6 month LIBOR plus 124.5 basis points	1
				$ (26)

In the Current Quarter, we sold call options to a counterparty with respect to two of the interest rate swaps above and received $4 million in premiums. If exercised, the call option on the 7.625% interest rate swap gives the counterparty the right to terminate the interest rate swap on July 12, 2007 for a payment to Chesapeake of $2 million. The call option on the 6.50% interest rate swap gives the counterparty the right to terminate the interest rate swap on August 15, 2007 for a payment of $2 million to Chesapeake.

In the Current Quarter, we closed one interest rate swap for a gain totaling $1 million. This interest rate swap was designated as a fair value hedge, and the settlement amount received will be amortized as a reduction to realized interest expense over the remaining terms 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 ($802 million at March 31, 2007) using an exchange rate of $1.3374 to 1.00. The fair value of the cross currency swap is recorded on the consolidated balance sheet as a liability of $20 million at March 31, 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 March 31, 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]
January 1, 2007 through January 31, 2007	243,269	$ 27.982		
February 1, 2007 through February 28, 2007	4,271	30.337		
March 1, 2007 through March 31, 2007	5,834	30.852		
Total	253,374	$ 28.088		

(a) Includes the deemed surrender to the company of 5,798 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 247,576 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***

Not applicable.

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.
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 3.2 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2003.
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.
32.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

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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: May 8, 2007

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